PHD

# Cost reflective network pricing for high voltage and low voltage distribution networks

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# Cost-Reflective Network Pricing for High Voltage and Low Voltage Distribution Networks

By

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Signature:…………………………… Date:………………………………

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# Abstract

Within the context of privatisation and deregulation in power industry, network users such as demand and generation should pay for their use of the networks, which always takes the form of Use-of-System (UoS) charges. Distribution network pricing is crucial in playing two roles: 1) ensuring economic efficiency, i.e. sending price signals to inform users of the network with respect to the costs they impose on networks and to influence the future behaviours of prospective users for efficient utilisation of existing networks; 2) enabling Distribution Network Operators (DNOs) to recover network investment costs.

In the UK, Distribution Reinforcement Model (DRM) has been the foundation of the network charges setting since the early 1980s. However, this approach neither reflects the extent of use of the network by users, nor provides price signals to influence the behaviours of users in the network. Hence, lack of economic efficiency of the DRM makes it necessary to develop new charging mechanisms for distribution networks.

The reform has been undergoing for Extra High Voltage (EHV Distribution-132kV, 33kV and 22kV in the UK) distribution networks, for which two new charging models are considered as the best available approaches by industry to achieve high level of economic efficiency, i.e. Long Run Incremental Cost (LRIC) and Forward Cost Pricing (FCP). However, the current DRM pricing model is retained for the High Voltage (HV Distribution -11kV and 6.6kV in the UK) and Low Voltage (LV Distribution-0.4kV in the UK) network charging because of: 1) the complexity of the two models; 2) the extensiveness of network configuration and limited available data.

The main objective of this thesis is to propose new charging models to achieve economic efficiency for HV and LV distribution networks. On the one hand, the key cost drivers need to be assessed properly as charges should be levied in line with what drives network costs. In this study, thermal and voltage constraints are the main cost drivers considered for HV and LV network investment. On the other,

given that charges are to influence future behaviours, the investment costs in the determination of charges should be future network costs rather than historical costs.

This thesis presents the original contributions in the following aspects:

- A new charging model for HV distribution networks is developed. Future investment costs are identified by determining the required reinforcement in terms of the two cost drivers under a projected load growth. The investment costs are allocated among users according to their 'contribution' into the costs to determine the charges. The underlying idea is grounded that costs should be allocated to those who cause them and by how much. The charging model provides locational and cost-reflective charges to users: the more costs they incur, the higher the charges are.
- A novel statistical model to quantify future investment costs is proposed for large-scale LV distribution networks. Due to the extensiveness of network configuration and limited approachable data, the triangular probability distribution is used to represent the distribution of utilisation levels of circuits and transformers in LV networks. The representation allows the assessment of the scale of network assets to be reinforced based on probabilities. The quantification of future investment costs provides a basis in developing a charging model for LV networks.
- Considering the increasing number of Microgeneration (MGs) connected at distribution networks, this thesis assesses the economic efficiency of LRIC in guiding future MG installation. A novel approach is introduced to quantify the investment deferral resulted from MGs for assisting the assessment.
- Since cost allocation theory always comes in terms of average cost and marginal cost, the debate on the choice between these two is on-going by researchers. In this thesis, preliminary analysis and discussion between these two cost reflective mechanisms is carried out for LV network charging models.

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# List of Abbreviations

| | |
|---|---|
| ARC | Average Reinforcement Cost |
| CDCM | Common Distribution Charging Methodology |
| CF | Coincidence Factor |
| CHP | Combined Heat and Pump |
| CN | Central Networks |
| DECC | Department of Energy and Climate Change |
| DG | Distributed Generation |
| DNO | Distribution Network Operator |
| DRM | Distribution Reinforcement Model |
| DUoS | Distribution Use of System |
| DWC | Distribution Wheeling Charge |
| EHV | Extra High Voltage |
| ESQC | Electricity Safety, Quality and Continuity |
| EU | European Union |
| FCP | Forward Cost Pricing |
| GSP | Grid Supply Point |
| HV | High Voltage |
| ICRP | Investment Cost Related Pricing |
| LF | Load Factor |
| LRIC | Long Run Incremental Cost |
| LTDS | Long Term Development Statement |
| LV | Low Voltage |

| | |
|---|---|
| MG | Microgeneration |
| MP | Multistage Planning |
| O&M | Operation and Maintenance |
| Ofgem | Office of Gas and Electricity Markets |
| OH | Overhead lines |
| PDF | Probability Density Function |
| PV | Photovoltaic |
| SE | Successive Elimination |
| SMD | Simultaneous Maximum Demand |
| SSE | Scottish and Southern Energy |
| TUoS | Transmission Use of System |
| UG | Underground Cables |
| UKPN | UK Power Networks |
| UoS | Use of System |
| WPD | Western Power Distribution |

# List of Symbols

| | |
|---|---|
| $PV_l$ | Present Value of future investment; |
| $PV_{lNew}$ | New Present Value of the future investment; |
| $\triangle PV$ | Change of the present value; |
| $M$ | Total number of asset in the network; |
| $d$ | Discount rate; |
| $Asset_l$ | Modern equivalent assets cost; |
| $n_l$ | Time to reinforce a network asset if no MG is installed; |
| $n_{lNew}$ | New time to reinforce a network asset if MG is installed; |
| $V_{drop}$ | Voltage Drop; |
| $Cost_T$ | Reinforcement costs driven by thermal violation; |
| $Cost_v$ | Reinforcement costs driven by voltage violation; |
| $L_{ij}$ | Length of circuit *ij;* |
| $P_i$ | the load connected at bus *i* |
| $UnitCost_i$ | Unit cost  for load at bus *i*; |
| $PeakDemand_i$ | Peak demand in Area *i* ; |
| $CF$ | Coincidence Factor ; |
| $Util\_ave_i$ | average utilisation in the target area*i ;* |
| $capacity\_unit$ | the typical capacity of each transformers in the target area*i* ; |
| $L_{unit}$ | the average length of circuits ; |
| $No\_feeders$ | the average number of feeders connected from each transformer; |
| $No\_transformers_i$ | the total number of transformers; |
| α | the lower limit of triangular distribution; |
| β | the upper limit of triangular distribution; |
| γ | the mode of triangular distribution; |

| | |
|---|---|
| $P_{thermal}$ | the proportion of the network assets represented by the shadow area; |
| $N_{assets}$ | the total number of assets in the system; |
| $Cost_{unit}$ | the unit cost of typical network assets; |
| $R_0$ | the resistance per unit length; |
| $X_0$ | the reactance per unit length; |
| $l$ | the circuit length; |
| $\Delta V_{max}$ | the maximum allowed busbar voltage drop; |
| $h(s_i)$ | the probability densities of loading level $S_{i;}$ |
| $h(l_i)$ | the probability densities of circuits length $l_{i;}$ |
| $\varphi$ | Power factor angle; |
| $T_{ij}$ | the product of loading level $S_i$ and circuits length $l_{i;}$ |
| $P_{voltage}$ | the proportion of circuits having voltage violation; |
| $Amount_{circuits}$ | the total number of circuits in the target network; |
| $TransCost_{unit}$ | the unit cost of transformers; |
| $S_0$ | circuit rating; |
| $AF$ | Annuity Factor; |
| $r$ | Load growth; |
| $U$ | the average utilisation of the network; |
| $n_{old}$ | the number of years U reaches '1'; |
| $Asset$ | the modern equivalent asset cost of the LV network; |
| $n_{new}$ | the new number of years U reaches '1'; |
| $IC$ | the annualised incremental cost of the network; |
| $\Delta D$ | the total incremental load; |

# Chapter 1

# Introduction

# 1.1 Background

## 1.1.1 Deregulation and Privatisation of the Power Industry

In the early 1990s, in order to create a competitive electricity market and ensure financial independence of this market from Government, deregulation and privatisation was introduced into England and Wales in the electricity energy sector. The reform was also seen by many other countries worldwide. Since then, market forces have been playing a vital role in network planning and operation whereas government's intervention is eliminated to the minimum extent. Under this circumstance, the need for price transparency and reduction of cross-subsidies for customers, higher energy efficiency in technical systems of utilities and significant growth in energy demand are recognised[1]. Meanwhile, the relationship between network utilities and the users such as generation and demand is commercial under the new environment. Network operators provide their networks to users to transfer their energy supply. Therefore, the users should pay for their use of the networks, which takes the form of Use-of-System (UoS) charges, appearing both at transmission and distribution levels

## 1.1.2 Climate Change and Energy Use

### 1.1.2.1. **Climate Change Issue**

Over the past decades, global climate change has been considered as a major threat to our common future. The increased greenhouse gas emission from the burning of fossil fuels and from land use change is leading to a warming of the climate. On the one hand, the effect of climate change, such as temperature, precipitation and the frequency of extreme weather events will vary greatly from place to place;on the other, the increasing greenhouse gas leads to ocean acidification, which risks profound impacts on many marine ecosystems and in turn the societies which depend on them [2]. Therefore, the climate change issue has become a subject of intense public and political debate.

#### 1.1.2.2. Government's Policy to Combat Climate Change in the UK

The UK government has a commitment to reduce the greenhouse gas emissions by at least 80% by 2050 relative to 1990 levels. In order to meet this target, the government has set down carbon budgets to make sure the UK is on track [3]. The impact of these regulatory schemes has been enhancing the use of renewable energy and 'cleaner' generation technologies. The overall target has been set out to ensure 15% of energy in the UK is coming from renewable sources by 2020 [4]. The detailed 2020 renewable energy target in each energy consumption sector is suggested in [4] as follows:

1. More than 30% of electricity generated from renewables, up from about 5.5% today. Much of this will be from onshore and offshore wind power, but biomass, hydro and wave and tidal will also play an important role.

2. 12% of heat generated from renewables, up from very low levels today. It is expected to come from a range of sources including biomass, biogas, solar and heat pump sources in homes, businesses and communities across the UK.

3. 10% of transport energy from renewables, up from the current level of 2.6% of road transport consumption. The government will also act to support electric vehicles and pursue the case for further electrification of the rail network.

#### 1.1.2.3. Advent of Renewable Distributed Generation

Under this circumstance, in the electricity consumptions sector, the use of renewable energy, commonly in forms of Distributed Generations (DGs), will be a key element to combat the climate change. DGs are small-size generators connected to or near load centres to meet demand. The use of DGs could significantly reduce $CO_2$ emissions and therefore meet the environmental target. Additionally, DGs have substantial technical and economic benefits for network operation and planning, such as reducing electricity losses, preventing power cuts and deferring network upgrade, etc. Nevertheless, from the long term network planning perspective, challenges are also brought by DGs integrating into networks, such as recognition of such benefits.

## 1.2 Research Motivation

Under the circumstances of deregulation and privatisation, one of the most important objectives is to promote a high degree of efficiency by introducing competition into the relationship between generation, transmission, distribution and retail activities. Currently in England and Wales, generation and supply have been open to competition whereas transmission and distribution, which are considered natural monopolies, are subject to price regulation. In the case of regulated monopoly, high efficiency can only be achieved by designing a tariff scheme that can send efficient economic signals to network users. For example, a good tariff scheme given to customers in distribution networks can help them shift the peak demand to off-peak hours, which can delay network upgrading required. In the UK, tariff design comes in the form of UoS charges to network users for their use of the network, which appears at both transmission and distribution levels, defined as Transmission Use of System charges (TUoS) and Distribution Use of System (DUoS) Charges. This research is only focused on DUoS.

Presently in the UK, different DUoS charging methodologies are designed according to voltage levels. For Extra High Voltage (EHV Distribution-132kV, 33kV and 22kV in the UK) distribution networks, Long Run Incremental Cost (LRIC) [5]and Forward Cost Pricing (FCP) [6]are considered by the industry as the best available approaches to achieve the high level charging principles: cost reflectivity, simplicity and predictability. LRIC was developed by the University of Bath in conjunction with the Western Power Distribution (WPD) Company whereas FCP was designed by Central Networks (CN), Scottish Power Energy Networks and Scottish and Southern Energy (SSE) Power Distribution, known as G3.

The LRIC pricing is to reflect the impact on future investment because of injection or withdrawal of generation or load at each study node. It makes use of the headroom or spare capacity of an electrical component or circuit to gauge the length of time before investment to reinforce the network is required. The final cost is the accumulation of the present values of the cost of all affected network components in supporting a nodal injection or withdrawal. The FCP pricing works on a very different pricing principle. It evaluates the total network investment cost over the next 10 years based on the forecasted generation and demand growth over the 10-year period. Thereafter, the identified investment cost is subsequently allocated to each customer group so that the total revenue recovered equals the forecasted reinforcement cost over the period[7].

Both LRIC and FCP require a full AC load flow and contingency analyses to determine the time to reinforce network assets. They offer more cost-reflective assessment of future reinforcement at the cost of significantly more complicated power flow analysis. However, network configuration in High Voltage (HV Distribution -11kV and 6.6kV in the UK) / Low Voltage (LV Distribution-0.4kV in the UK) networks is extensive and therefore power flow tools are deemed too complicated to be practical for these networks.

Therefore, due to the complexity of the two economic charging methodologies, it is agreed by the industry in the UK that Distribution Network Operators (DNOs) use a Distribution Reinforcement Model (DRM) to charge lower voltage distribution network users. The DRM model uses an approach outlined by [8] in 1977 for cost reflective network charges in England and Wales. This model measures the investment costs of an additional 500MW of capacity and averages this cost across users connected at HV/LV networks[9]. One of the major shortcomings of the DRM model is that the evaluated costs for 500MW capacity are simply scaled from the current existing asset costs without recognising the system assets utilisation as well as the impact of future load growth. Furthermore, it is widely recognised by both academic researchers and industrialists that lack of effective price signals either for customers or DNOs makes DRM impossible to guide future demand and generation development. Overall, the DRM model does not take into consideration the anticipated demand growth and the available capacity of the network but estimates 'future' reinforcement costs brought by 'hypothetical' demand based on historic data.

Overall, the improvement on the effectiveness of the network charging methodology on HV and LV networks has become a concern.

## 1.3 Research Objectives

To achieve efficient DUoS charging methodologies, firstly the network condition needs to be recognised properly, which can address the cost/benefits associated with network users. Secondly, future network development should be considered in order to provide forward-looking charges for network users. Thirdly, charging methodologies should be simple to implement.

The main objective of this work is to develop novel network pricing methodologies for HV and LV distribution networks. Considering the different characteristics between HV and LV distribution networks such as extensiveness of network configuration as well as network information availability (a detailed discussion takes place in Chapter 3), separate approaches are developed accordingly.

Specifically, the study aims to achieve the following detailed objectives:

1. To quantify potential investment deferral brought by Microgeneration (MGs) on distribution networks and to evaluate the effectiveness of LRIC charges in guiding the allocation of MGs in distribution networks; this work is to address the fact that an appropriate network charging model could lead to efficient network development.

2. To assess key cost drivers imposed on the development of HV and LV distribution networks by network users;

3. To allocate the costs in a cost-reflective manner among network users by recognising their 'extent of use' of networks: the greater the 'extent of use', the higher the charges;

4. To provide forward-looking economic signals for users to help them make decisions on the site and size of future demand and/or generation, in order to guide network development in an efficient direction;

5. To devise 'simple-to-use' charging models for HV and LV distribution networks, by utilising limited network data information and reduce computation burden in deriving charges.

## 1.4 Research Challenges

During the research, in achieving the objectives set in the previous subsection, the following major challenges are faced:

1. **Assessment of investment deferral brought by MGs**

In order to illustrate the effectiveness of DUoS charges as guidance for the installation of MGs in distribution networks, it is crucial to quantify investment deferral with regard to the integration of MGs. The investment deferral brought about by MGs should be recognised in terms of different locations and sizes. To do so, developing an appropriate approach to quantify investment deferral in this study is necessary and challenged as no previous studies available can be applied to fulfil this objective. Meanwhile, the siting and sizing of MGs are not necessarily decided by DNOs; incentives or charging schemes can be considered by DNOs to guide the most beneficial location and capacity of MGs.

2. **Identification of reinforcement cost drivers and Allocation of reinforcement costs for HV networks**

To develop cost reflective use-of-system charges, two elements need to be addressed. The first key point is to identify cost drivers for long-term reinforcement properly. The cost drivers always involve thermal violation or voltage violation due to demand/generation growth. The second key point is to allocate the reinforcement costs in a cost reflective manner. Hence, it is essential to develop an approach to address these two aspects accordingly.

**3. Modelling the LV networks condition in terms of urban, suburban and rural**

Because of the extensiveness of large-scale LV networks and often the shortage of detailed network assets information, it is critical to establish an appropriate model to recognise the LV network conditions. It is proposed to categorise LV networks into urban, suburban and rural networks considering different load density in different areas. However, the load densities for different areas are not available. Therefore, it is necessary to determine load densities making use of potential approachable data. Moreover, in LV networks, available network assets data is generally held at the aggregated system level, including the total number of assets, such as number of transformers, total length of underground cables and overhead lines, the total capacity of transformers and the peak demand. Hence, disaggregating network assets into urban, suburban and rural areas is necessary.

**4. Quantification of future reinforcement costs for LV networks**

Due to the extensiveness of network configuration and limited access to the specific assets loading conditions in LV networks, power flow tools, which are always used in higher voltage levels to evaluate the necessary reinforcement costs, cannot be practically used for the purpose of overall system level network investment planning in LV networks. Currently in the UK, in need of future reinforcement costs for LV networks, historic data for past years is simply scaled to be the future costs. Such linear extrapolation can neither estimate the current system conditions nor forecast the future development trend. Therefore, a new methodology is needed for the determination of the total reinforcement costs. The two major difficulties here are 1) modelling the huge amount of assets associated with demand growth activities and 2) assessing the drivers of reinforcement activities.

**5. Charging models using different cost allocation theories: average cost and marginal cost**

Cost allocation theory always comes in terms of average cost and marginal cost. The debate on the choice between these two is on-going by researchers. According to standard economic theory, prices should be set at marginal cost because it can provide more efficient economic signals than average cost. However practical issues appear when setting price using marginal costs. For example marginal cost will be relatively low when system capacity utilisation is low. In this respect, the cost recovery cannot be ensured and therefore additional action is needed to fulfil the cost recovery. The analysis between the two theories needs to be addressed properly when devising a charging model for practical systems.

## 1.5 Major Contributions of this Thesis

The main contributions of this work can be summarised as follows:

1. It brings a comprehensive understanding of the DUoS charging principles currently used in the UK and to illustrate the necessity of developing new charging methodologies for HV and LV networks;

2. It develops a new approach to quantify the economic benefits brought by MGs in terms of investment deferral; comparison of the resulted benefits is conducted between different scenarios considering different penetration, concentration levels and allocation of MG units in networks. Suggestion is given that in order to achieve the maximum benefits in terms of investment deferral, the locational DUoS charges could be given as incentives for MGs.

3. It develops a new DUoS charging methodology for HV distribution networks, providing cost reflective charges. Reinforcement costs are investigated in terms of thermal violation and voltage violation due to demand growth. UoS charges are derived by allocating the reinforcement costs regarding 'extent of use' of system users.

4. It proposes a logical and novel approach to categorise LV networks into urban, suburban and rural networks by recognising the load densities in each subarea; To do so, load density is calculated by using energy consumption data, population density and population sizes, which can all be approached from public resources. Secondly, the aggregated network assets data in LV networks,

i.e. the total length/numbers of assets (circuits/transformers), and total peak demand, is disaggregated into urban, suburban and rural areas.

5. It puts forward a novel methodology to estimate and quantify future reinforcement costs at system level using statistical theory for large-scale LV networks. Triangular probability distribution is used to represent the distribution of utilisation levels of circuits and transformers. An increase in the average loading level in the system will result in shifting the probability distribution, which will allow the scale of network assets needed to be reinforced to be assessed based on probabilities. The reinforcement costs for a given period are determined by the sum of the total number of circuits and transformers to be reinforced based on the evaluated probabilities, typical capacities and the costs of these assets. The proposed statistical method is implemented using a practical distribution system.

6. It develops a new cost-reflective charging methodology for LV networks using average cost theory. The model allocates the estimated future reinforcement costs among network users on an average basis.

7. It proposes a new charging model for LV networks using incremental cost theory. Besides, the comparison between the two approaches is discussed.

## 1.6 Thesis Outline

The layout of the thesis is presented as follows:

Chapter 2 presents a literature review on distribution network planning under the new circumstances. Following the introduction about power system structure, the new technical and economic challenges appearing in distribution network planning are summarised. Literature involving evaluation of network investment deferral brought by MGs/DGs is therefore specifically reviewed.

Chapter 3 provides a comprehensive literature review on the principles of DUoS charging methodologies used in the UK. The difference between different charging models and their limitations are firstly both investigated. The necessity of developing new charging methodologies for HV and LV networks are therefore explained.

Chapter 4 proposes a new approach for quantification of the network investment deferral brought by MGs. The approach firstly evaluates the reinforcement horizon of networks with and without the presence of MGs. The investment deferral is therefore obtained by the difference between the present values of assets under the respective time to reinforce. The methodology is demonstrated on a practical system.

Chapter 5 proposes a new charging model for HV distribution networks. The charging model can reflect the 'extent of use' of network assets

Chapter 6 outlines the approach to categorise LV distribution networks into urban, suburban and rural areas. The work in this chapter is the premise of the work in the following two chapters.

Chapter 7 proposes a novel statistical method for quantifying the reinforcement costs in LV distribution networks driven by demand growth. The approach can effectively model network utilisation and therefore estimate the required investment.

Chapter 8 proposes a new charging model for large-scale LV distribution networks using average cost principle.

Chapter 9 presents a new charging model for large-scale LV distribution networks using marginal cost concept. Furthermore, the comparison between the two charging models is carried out in this chapter.

Chapter 10 summarises the key findings from the thesis.

Chapter 11 outlines potential future works.

# Chapter 2

# Distribution Networks in New Environment

## 2.1 Development of Electricity Networks: Physical Structure

### 2.1.1 Structure of Traditional Electricity Networks

Electricity networks have evolved to interconnected national transmission and distribution networks from localised street systems around 120 years ago. The structure of a typical electric power system in the UK is shown in Figure 2-1. The electricity is produced from power station, stepped up by transformers in voltage and then delivered by transmission networks. The electricity is then stepped down in the primary substations to distribution networks and then delivered to different supply points. After that, it is stepped down through regional substations or local transformers and delivered to customers. There are some large customers, industrial factories for instance, connecting directly to the transmission networks to ensure the huge amount of demand.

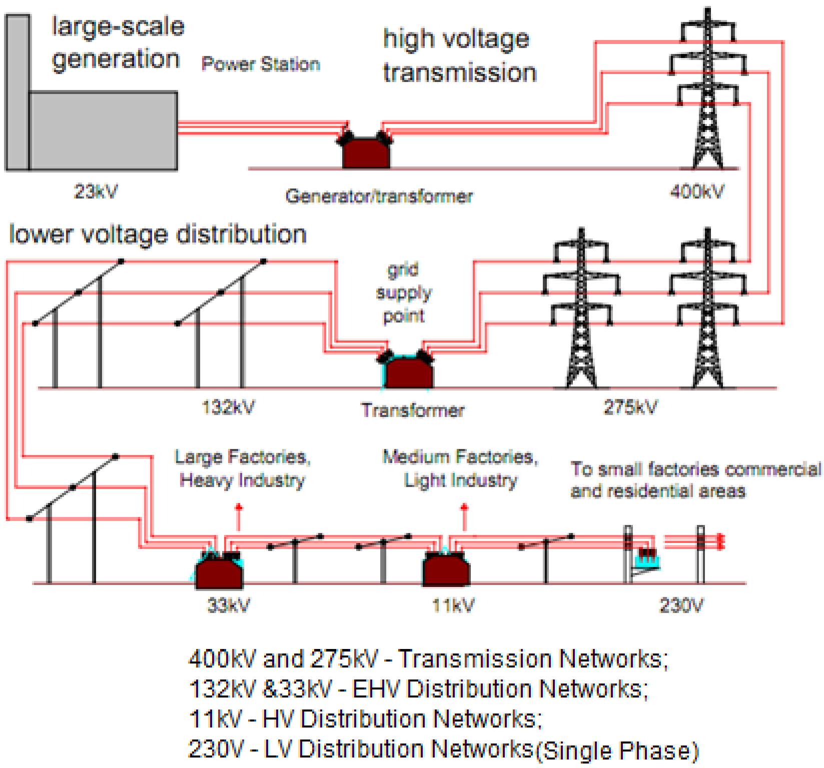


**Figure 2-1 UK Traditional Electricity Network Structure[10]**

### 2.1.2 Structure of Evolving Electricity Networks with DGs

Since the late 1980s, significant changes have been occurring within distribution networks because of environmental, technical and economic drivers[10]. The environmental driver is the target of $CO_2$ emission reduction set by the governments due to the awareness of climate change. Meanwhile, in terms of technical drivers, there are significant advances in generation technologies, such as fuel cells, wind turbines and photovoltaic. Furthermore, in terms of economic drivers, the deregulation and competition policy aims at ensuring the lowest possible costs for all consumers, and the economic benefits of DG have received widespread awareness.

In this context, the necessity of generating electricity from renewable resources has been emphasised by the UK government, particularly those in small sizes. Consequently, a great number of renewable DGs have been emerging. DGs are small-size generators connected at lower voltage distribution networks close to the load centre. They aim at providing electricity to factories, offices and households. Moreover, the produced electricity by DGs can be fed back into distribution networks to meet demand elsewhere if customers in the premise with DGs cannot consume all of it. Alternatively, electricity storage can be used to store the excess electricity generated by DGs. The overall structure of electricity networks with DGs is illustrated in Figure 2-2.

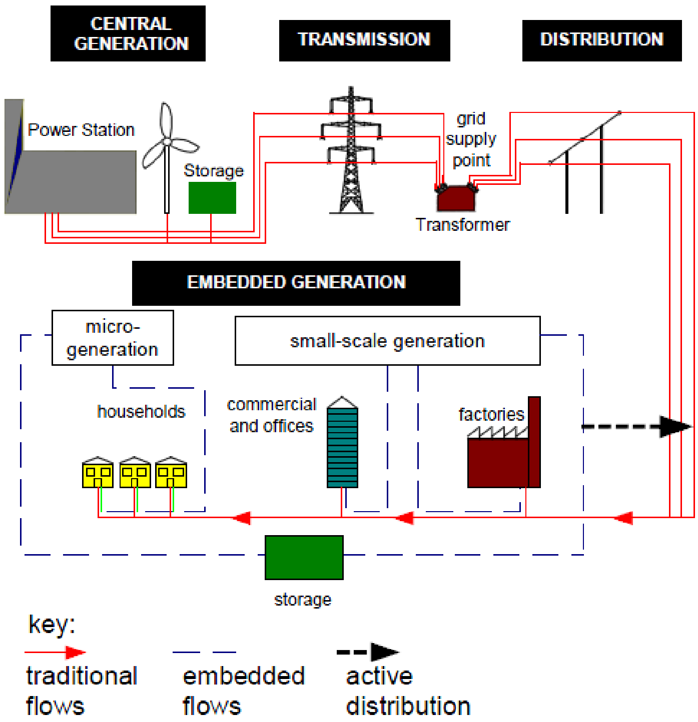


**Figure 2-2 Electricity Networks with DGs[10]**

Traditionally, distribution networks are designed to receive electricity from the high voltage transmission networks and deliver it to individual customers, which are considered passive networks. With DGs connected, electricity networks are evolving from a passive state to a more active one with bi-directional power flows between different voltage levels.

## 2.2 Distribution Networks with DGs

### 2.2.1 Definition of DGs

DGs are loosely defined as small-scaled generation connected to distribution networks or directly to customer's premises. The examples of typical DGs are small scale Combined Heat and Pump (CHP) or renewable generation: small hydro, wind turbine, solar power, biomass power and so on.

MG is one type of DG with a very small capacity up to 50kW[11], which can provide electricity to a range of building sizes including homes, business, schools through various technologies such as Photovoltaic (PV), wind turbine and micro-CHP. MGs are always connected to LV distribution networks.

More detailed DG classification is shown in Table 2-1below[12].

**Table 2-1 Detailed DG classification**

| DG Types | | Typical size | Usage |
|---|---|---|---|
| Fossil Fuel based | Conventional gas turbine | 1MVA-100MVA | Industrial |
| | Gas engine | 8kVA-10MVA | Commercial, Industrial |
| | Micro turbine | 50kVA-1MVA | Commercial |
| | Stirling engine | 0.5kVA-50kVA | Domestic, Commercial |
| | Low temperature fuel cell | 0.5kVA-100kVA | Domestic, Commercial |
| | High temperature fuel cell | 300kVA-5MVA | Commercial |
| Renewable based | Micro hydro | 5kVA-1MVA | Grid Power |
| | Small hydro | 1MVA-100MVA | Grid Power |
| | Wind turbine | 0.5kVA-5MVA | Grid Power |
| | Biomass | 100kVA-50MVA | Grid Power, district heating |
| | Photovoltaic | 0.1kVA-500kVA | Domestic, Commercial |
| | Geothermal | 5MVA-100MVA | Grid Power |
| | Wave & tidal | 100kVA-1MVA | Grid Power |

### 2.2.2 DGs Benefits

Various benefits of DG on distribution networks have been recognised [13-15]. The major benefits in terms of three aspects, environmental, technical and economic, are discussed in the following subsections.

#### 2.2.2.1. **Benefits from Environmental perspective**

Around 40% of carbon dioxide emissions comes in the process of electric power generation, a primary contributor to climate change[16, 17]. Recent DG technologies provide an environmentally source of electrical energy and by 2050 a widespread installation of MGs could reduce household carbon emissions by approximately

15%[18]. In addition, the avoidance of the construction of new transmission circuits and large power plants are also important environmental benefits [19]. Furthermore, conventional power plants may produce an incredible amount of waste products such as exhaust gas and water. DGs are relatively better under the consideration of environmental issues. Renewable generation, such as wind and solar generation, is even "zero pollution".

#### 2.2.2.2. Benefits from Technical perspective

1. Power losses reduction;

Power losses along circuits are reduced due to the reduction of electricity travelling from upstream networks.

2. Voltage profile improvement;

Since DG can provide a portion of real and reactive power to the load, it can help to decrease the current along a section of the distribution circuit, which will result in a boost in the voltage magnitude at the customer site. Therefore, voltage profile can be improved [20].

3. System reliability and security enhancement;

DGs connected to distribution networks have the potential ability to enhance system security and uninterruptible service to customers, by maintaining supply to a defined level of demand under specified outage conditions [21].

Nevertheless, it should be noted that there are technical challenges coming along with increasing number of DGs, such as voltage rise and increasing fault level. The above mentioned benefits can only be achieved if they are managed properly.

#### 2.2.2.3. Benefits from Economic perspective

Economic benefits can be addressed in two aspects regarding the stakeholders involved, customers and DNOs [22]. For customers, reduced electricity bill is the key benefit to install DGs. For utilities, since DGs are connected close to load centres, the need for building and upgrading the upper stream distribution network infrastructure is reduced, which can defer or avoid the necessity of investment. Thus, investment deferral is the key benefit brought for DNOs. Research conducted by [23] has found deferral benefit values of up to $1200 USD per kW of operating DGs depending on the location of the DG and the load growth rate.

#### 2.2.2.4. **Recognising the Benefits of DGs in Distribution Network Planning**

One of the objectives in distribution network planning is to minimise distribution investment and operating costs and maximise the profit in the long term. DGs as an alternative source of power play an important role to achieve this objective. Regarding DG development, integration and policy-making, one of the main priorities by regulators is the development of incentives or other commercial mechanisms to encourage favourable DG solutions. Development of such mechanisms requires a clear understanding of how beneficial a particular DG is, and the extent of such benefit in monetary terms [22]. Most of the benefits of employing DG in existing distribution networks have both economic and technical implications and they are interrelated. Ultimately, all the benefits from DGs can be quantified in terms of money[24]. The monetary benefits can not only be considered as incentives for DGs but also provide an assessment tool for distribution network planning. Therefore, it is essential that these benefits from DGs be clearly recognised, analysed and quantified in order to increase the potential and value of DG penetration by finding out the most economical DG options.

In this thesis, the scope of quantifying these benefits is restricted to investment deferral, which is discussed in the following section.

### 2.2.3 Investment Deferral of Distribution Networks by DGs

#### 2.2.3.1. **Definition of Investment Deferral**

Investment deferral refers to delaying the need of expenditures for acquiring and installing new assets or upgrading existing ones for higher capacity in order to meet the forecast peak load[25].

#### 2.2.3.2. **Literature Reviews on Assessment of Investment Deferral**

In order to meet future load growth, DNOs need to invest in new power transformers or distribution feeders. As previously discussed, it has been widely recognised that DGs have the potential to defer the expansion or upgrades of distribution networks due to load growth [14, 21-23, 26-28]. In [14] a successive elimination (SE) algorithm was applied to distribution network expansion considering the specific location of DG. The investment required for the network expansion planning with and without the presence of DG was evaluated. And thereafter, the corresponding investment deferral can be obtained by the difference, without reference to the timing of investments. Following the work in [14], the SE approach was combined with Multistage Planning (MP) in [21, 28] to assess the deferment of investment by DGs. The MP analysis in this work aims to schedule the implementation of the reinforcement costs obtained from the successive elimination approach along the planning horizon. The impacts of DGs on both demand growth and system security-related investment are quantified, by recognising the difference between the costs required for the original scenario and the DG scenarios.

A different approach was developed to quantify the investment deferral caused by DGs in distribution networks in [23]. The approach is based on the amount by which network radial feeder currents are reduced by a DG unit and the benefit is given in monetary units per connected kVA. Results in [23] suggest that the economic benefit would be increased when DG units are installed at the end of distribution feeders. However, the investment deferral is based on the time required for feeder currents to reach the level prior to the connection of DG, which is considered to be not appropriate. Investment deferral should be quantified relative to the time when reinforcement costs are incurred as suggested in [21, 28].

Similar research was carried out in [27], where the authors proposed a probabilistic approach based on a Monte Carlo simulation to assess network deferral value of DG units in the long term. The authors demonstrated the impact of different DG penetration and concentration levels and technology mixes on allowable load growth without the need for reinforcements. The results suggest DGs can increase the original allowed load growth in the networks without DGs, which, therefore, can postpone the necessary investment. However, this study cannot be used for quantifying the relative benefit that DGs may bring about according to its location. Work in [26] aims at analysing different regulations for a DNO to capture the effects of network planning options on DG unit expansion. It adopted the investment deferral evaluation method proposed in [28] and the reinforcement strategy in [23], i.e. the network was divided into several groups of feeders, when a feeder overloads not only the corresponding feeder is reinforced but also parts of the downstream feeders in the same group.

Overall, as discussed above, methodologies for the evaluation of investment deferral have been discussed extensively. However, little analysis was carried out on the literature, which discusses the impact of the location, penetration and concentration levels of MGs on the investment deferral. In particular, as an increasing number of MGs integrated in LV networks, the aggregated capacity of MGs will have a significant impact on the higher voltage level distribution networks. In addition, installation of MGs/DGs relies on customer willingness. However, in the literature, few analyses discuss strategies to achieve the most investment deferral by providing appropriate economic signals to customers.

## 2.3 Chapter Summary

This chapter introduced the development of distribution networks in a new environment. The important role of DGs in this new environment was addressed along with the impact of DGs on distribution networks in terms of environmental, technical and economic impacts. One of the benefits brought by DGs on distribution networks, investment deferral, was highlighted and the methodologies for assessing the benefits in the literature were reviewed. This chapter provided background information for quantifying investment deferral for MGs in chapter 4.

# Chapter 3

# Literature Review on Use of System Charging Methodologies

## 3.1 Introduction

Network companies have no control over the size, location and type of future generation and demand. However, they can use financial incentives to guide them to locate where there is plenty of spare capacity and therefore where the least network upgrading is required. These financial incentives can be incorporated in the form of charges for use of system[5, 29]. The other primary purpose of use of system charges is to recover the costs of capital, operation and maintenance of a transmission or a distribution network, allowing the network companies to earn a reasonable rate of return on the capital invested.

Generally, there are two stages in setting use of system charges:

1. The determination of total costs, which can be obtained from the historic costs of accommodating existing network users only, the future costs of accommodating network customers only or some composite of both approaches[30-35];

2. The allocation of the total costs among the users of the networks; a number of cost allocation methodologies have been developed. The postage stamp approach is considered to be the simplest one as it uniformly allocates network costs among users without regard to their location information[35]. The more advanced techniques differentiate the costs of use of system by users' location, i.e. 'extent of use' costs. The more efficient approach seeks to identify the change in the total costs associated with a change in demand on the system or specific location, which is often referred to as marginal costs or incremental costs[36].

## 3.2 Network Charging Methodologies

### 3.2.1 Charging Principles

Generally, principles that should be taken into account in charging methodologies are cost reflectivity, simplicity, transparency, predictability and the facilitation of competition [37]. The following discussion is carried out to explain the criteria in detail:

1. Cost reflectivity refers to the criterion that the costs incurred by serving each customer should be recognised and reflected in the charging models;

   Cost reflectivity can be addressed in two different manners, i.e. 'total' or 'incremental'[6]:

   i) Cost reflective in the 'total' sense if the charge reflects the total additional cost imposed on the network by a new customer or group of customers or the cost that would be saved by their complete withdrawal. The charges are always set equal to the costs on an average basis, i.e. total costs divided by expected total demand. In this manner, the expected costs can be fully recovered.

   ii) Charges are cost reflective in the 'incremental' sense if it reflects the cost of supplying a customer at the margin. In other words, it reflects the additional cost incurred by the producer from increasing supply to a customer that demands more. In this manner, the expected costs are unlikely to be fully recovered.

   As for price signals, the total cost pricing reflects economic efficiency more aggregately whereas the incremental costs can inform customers of the costs if they increase their usage above its current level.

2. To meet the requirement of simplicity, the steps of deriving charges should be easy to follow and understand;

3. Transparency can be embodied in the charging model by utilising the publicly available sources of information as far as possible; moreover, the steps taken to derive the final charges should be clearly set out in order to be transparent to anybody, so they can replicate the charging model's outputs if they wish to do so;

4. The reason for promoting predictability is to provide customers with reliable forecasts of charges and minimise uncertainty to customers.

5. Promotion of competition in the context of distribution charges relates primarily to competition between retail businesses.

In general, it is acknowledged that the trade-off between achieving the criteria mentioned above is inevitable when designing the charging models. For example, the charging models with higher cost reflectivity would have more complex structure and bring a bigger computation burden, which might conflict with the criterion of simplicity and transparency. Therefore, the fulfilment of all the criterions is not practically possible and the balancing between the principles needs to be considered[6] .

## 3.2.2 Cost Allocation Theory

Generally, two types of approaches are widely used to allocate costs in network charging model design: embedded cost method and incremental/marginal cost method.

### 3.2.2.1. **Embedded Cost Method**

Embedded cost is defined as the revenue requirements needed to pay for all existing facilities plus any new facilities added to the power system [38]. The most common embedded cost is the capital cost of transmission and distribution infrastructure [39].

Four different embedded cost methods [36]are discussed as follows:

1. Postage Stamp Method

This technique is commonly called Rolled-In-Embedded Method [40]. It divides total costs of the system by MW of demand or supply, regardless of the actual condition of the system. The costs as determined are independent of the distance of the power transfer, which is the reason why the method is called the postage stamp method. The postage stamp method has no real locational message for customers regardless of the different impacts on the system from customers. Furthermore, the postage stamp charges cannot provide economic signals in order to achieve economic efficiency.

2. Contract Path Method

The method is based upon the assumption that power transfer is confined to flow along a specified electrically continuous path through the system. The changes in flows in facilities that are not within the identified path are ignored. The embedded capital costs are limited to those facilities that lie along the assumed path [40]. Compared with the postage stamp approach, this method takes greater account of location by measuring a distance power travels for [36]. However, the costs might not reflect the actual costs incurred by all customers due to the assumption made[41].

3. Boundary Flow Method[41]

The method incorporates the changes in MW boundary flows of the wheeling company due to a power transfer, either on a line basis or on a network interchange basis, into the cost of wheeling. Two power flows, executed successively for every year with and without each wheel, yield the changes in either individual boundary line or net interchange MW flows. The method uses power flow analysis, which can reflect the real condition of the system. But the issue of this method exists in that it only reflects the costs of existing facilities rather than the reinforcement costs due to demand change.

4. Flow-Mile Methods [38]

The method can recognise the magnitude, path and distance travelled by the power, i.e. 'the extent of use', which is more reflective of the actual usage of network[34]compared with the postage stamp and contract path method. The limitation of this method is similar to the boundary flow method in that it only reflects the existing costs of networks, without considering the reinforcement costs due to demand change.

#### 3.2.2.2. **Incremental Cost and Marginal Cost**

Both methods seek to identify the change in the total costs associated with a change in quantity of load in the system or its location, and hence change in the pattern of flow[36].

Incremental cost can be defined as the revenue requirement needed to pay for any new assets that are specifically attributed to the customer. In contrast, marginal cost can be defined as the revenue requirements needed to pay for any new capacity in the system. The major difference between incremental and marginal pricing is in how they evaluate the cost due to additional transactions. Incremental approaches are carried out by comparing the cost with and without transactions. The costs are allocated to only the new customers that incur the needed reinforcement costs. Marginal approaches, on the other hand, evaluate the cost needed to accommodate a unit additional transaction and then multiply the unit cost with the actual size of the additional transaction [38].

## 3.3 International Experience of Network Charging

In Chile, cost structure for distribution is built to represent the industry costs, including costs of investment, operation and losses. These costs are finally allocated averagely considering distance and power magnitude. The models are built for each typical area and therefore provide different tariffs for different distribution companies [42].

In Germany, use of system charges are derived by allocating costs to different voltage levels using a cascading principle. A coincidence factor is considered by calculating the probability that the user's individual load coincides with the system peak[43].

The Distribution Wheeling Charge (DWC) in Brazil is designed based on two phases: the computation of the revenue requirement and the allocation of this revenue among the distribution users. The regulator determines the allowed revenue, which is the sum of the base rate returns and the operation and maintenance (O&M) costs. In the current stage of the distribution pricing in Brazil, only the voltage level is considered to establish the tariff. So, the marginal cost of each voltage level is computed and applied to allocate the distribution charges. It is like a "postage stamp" for each voltage level. Since the distribution companies are in charge of the entire network composed of voltages from 127 V to 138 kV, the consumers see one tariff for each voltage level no matter where they are located[44].

In France, access tariffs apply only to eligible consumers wanting access to the network. Prices are set on a national level and based on consumption and voltage rather than distance. The capacity charge is based on the subscribed demand and peak capacity at four points in the year (summer/winter-on/off peak) [45].

In Norway, the tariffs in the central grid consist of four elements: two dependent on the short-run utilisation of the grid and the other two are fixed on an annual basis. The tariff element covering losses is based on spot market prices of electricity and an approximation to the marginal loss caused by injection and consumption in a region for three typical load situations. This element covers approximately 25% of the total costs [46].

The network pricing in Spain provides short-run signals by pricing losses and congestions. In the case when the grid is less available than a determined reference level, the grid owner is penalised [47].

In New Zealand, electricity spot prices are equal to nodal marginal costs, and system expansions are justified if the difference in prices with and without a scheme equals the cost of the scheme [48].

## 3.4 Development of Charging Models in the UK

### 3.4.1 Present Charging Framework in the UK

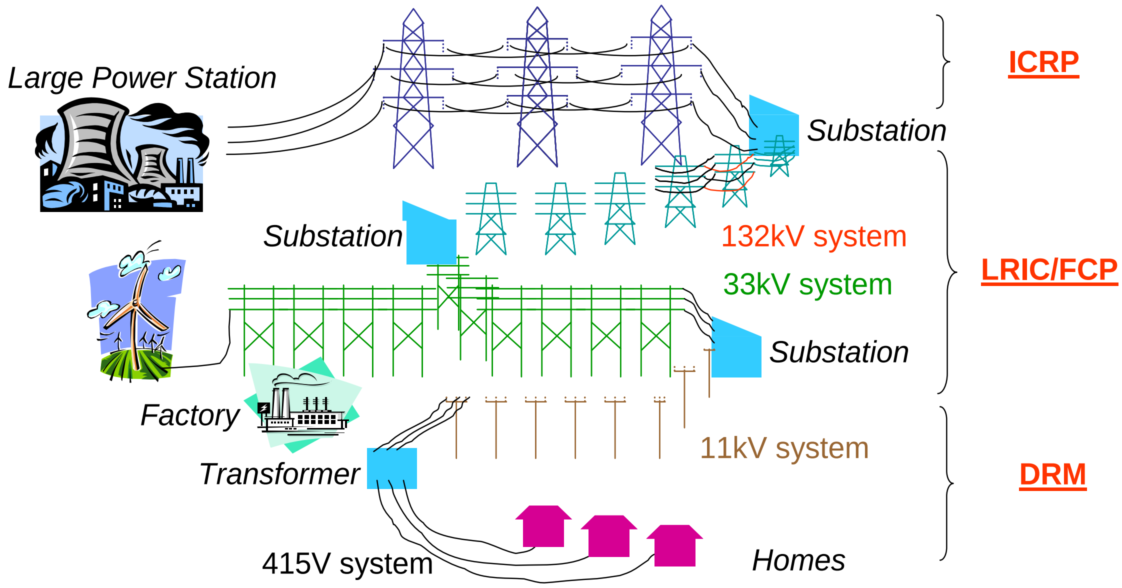


**Figure 3-1 Current Charging Framework of Electrical Networks in the UK[49]**

The present charging framework for electricity networks in the UK is illustrated in Figure 3-1. For transmission system, the ICRP (Investment Cost Related Pricing) model is utilised. For EHV distribution networks, two charging models are approved by Ofgem (Office of Gas and Electricity Markets), allowing DNOs to choose according to their preference. One is LRIC developed by the University of Bath teamed with WPD. The other one is the FCP model developed by GB's three DNOs – Scottish Power, Scottish Southern and Central Network. It is agreed by the industry that the DRM model is used for HV/LV network pricing, due to the complexity of LRIC and FCP[7].

### 3.4.2 Use of System Charging Model in Transmission Networks

The charges from the ICRP model are calculated from the incremental network cost of accommodating an additional 1MW increment at each study node [50]. The model identifies the circuits that support the injection or withdrawal of power from a study node and evaluation of the power flow changes in those circuits by a unit power change at the node. The ICRP charge at the study node is determined as the product of the power change of each supporting circuit and the unit cost of the circuit over all of the affected circuits[7].

Two main assumptions are made in the ICRP mode: i) the existing assets of network are fully utilised by the existing customers. Any additional power required from a study node will require immediate network reinforcement. Hence, no recognition of assets utilisation is considered in this model. ii) A circuit is infinitely divisible so that an additional 1MW power flow can be met by the addition of a circuit with 1MW capacity.

The ICRP model does not recognise the degree to which the existing assets are utilised, but only the distance. This means that when the degree of circuit utilisation varies, the respective marginal cost remains the same throughout[51]. In this circumstance, the ICRP charges would encourage a new demand to the nodes with short distance circuits but highly loaded. In contrast, the charges could attract generation to connect to the nodes with long distance to GSP (Grid Supply Point) but lightly loaded. Consequently, it may produce unstable charges that "flip flop" between debit and credit for generation and demand for the locations that are relatively distant from the grid supply point [52]. When this ICRP model is implemented into distribution networks, the 'flip-flop' effect becomes the major drawback of this model, as distributed generation is expected to sit close to load, which would eventually result in reverse power flow at certain parts of the network.

### 3.4.3 Charging Models in EHV Distribution Networks

#### 3.4.3.1. **Forward Cost Pricing Methodology**

The FCP methodology was developed jointly by Central Networks, Scottish and Southern Energy and Scottish Power, collectively known as G3 [6]. The FCP model can be considered as a combination of two sub-models: FCP demand approach and FCP generation approach as it treats demand and generation separately.

**1. FCP Demand Approach[6]**

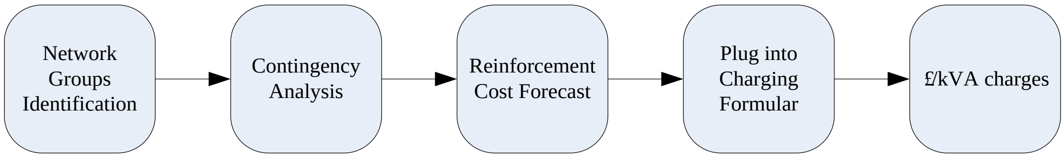


**Figure 3-2 Overview of FCP Model for Demand**

Figure 3-2 illustrates the overview of FCP demand approach, which involves four steps in deriving charges.

Firstly, each licensed distribution network is broken down into a number of 'network groups'. The number of network groups for each DNO depends on the physical characteristics of each network. FCP charges within the same network group are the same.

Secondly, once the network groups are identified, a contingency analysis is conducted for each group. The contingency analysis generates for each network group a set of estimates for the cost of reinforcement at different demand increments.

Thirdly, the assumed demand growth is combined with the information provided by contingency analysis to arrive at a set of estimates for when future reinforcements will be required on each network.

Finally, the preliminary £/kVA/year cost is generated for customers. To do so, it is assumed that the total revenue recovered over the 10-year period equals the forecasted reinforcement cost. The FCP charges for demand can be derived using (3-1)

$$FCP_{Demand} = 2d\left(\frac{AssetCost}{C}\right)\left(\frac{D}{C}\right)^{2d/r-1} \quad (3\text{-}1)$$

where $d$ is discount rate, *AssetCost* is the reinforcement costs, $C$ is the capacity, $D$ is the loading level and $r$ is the load growth rate.

**2. FCP Generation Approach[6]**

To derive generation charges using FCP, reinforcement costs are forecasted over the next 10 years for the same network groups respectively. Thereafter, the reinforcement costs are allocated across total expected generation over the 10-year period to arrive at a set of £/kVA/year charges. However, the difference exists in forecasting the reinforcement costs. For generation, 'test-size' generators are notionally connected at each voltage level to estimate reinforcement costs. Next, the costs are scaled down by an assumed probability of such a 'test-size' generator actually connected. The FCP charge for generation is derived using the following formula (3-2):

$$FCP_{gen} = \frac{AssetCost \times probability \times e^{-dn}}{10(G + G_{testsize} / 2)} \tag{3-2}$$

where $d$ is discount rate, *AssetCost* is the reinforcement costs, G is the existing generation in the network group and $G_{testsize}$ is the test-size generation.

FCP can recognise both the distance and the degree of utilisation of assets, which can be regarded with a high level of cost reflectivity. However, one study [53] shows some drawbacks of the FCP model. Firstly, the locational signal provided by FCP is weak as it groups nodes into a network group, which is given to the same charge. Moreover, for a lightly utilised network, there might not be reinforcement costs needed in the specified time horizon and hence zero charge is given. Apart from this, the probability of the connection of the test-size generator is directly used to scale the reinforcement costs, leading to high charges to high probability of connection. If higher new generation is forecasted, the probability of connection will increase, leading to higher charges. This pricing signal apparently contradicts with the aim of encouraging more new generation.

#### 3.4.3.2. **Long Run Incremental Cost Pricing**

The Long Run Incremental Cost approach [5]was developed by the University of Bath (UK) in conjunction with WPD to look at the time horizon until reinforcement is needed and to factor in the cost of that reinforcement. This proposed charging structure is an improved version over the UK's transmission pricing model-ICRP, in that it can reflect both the distance travelled and the degree of utilisation of the travelling path by nodal injection.

The LRIC charging method seeks to reflect the impacts on future investment in network components because of the injection or withdrawal of generation or load at each study node. For network components that are affected by the injection, there will be a cost associated with accelerating the investment, or a benefit associated with its deferral. Depending upon the magnitude of the reinforcement cost and the discount rate chosen, the present value of the cost for each affected network component can be calculated. The LRIC charges are the accumulation of the present values of the cost of all affected network components in supporting a nodal injection or withdrawal.

The detailed mathematical formula and principles are introduced as below:

If a network component $l$, such as a circuit, has a capacity of $C_l$, and supports a power flow of $D_l$, then the number of years it takes utilisation to grow from $D_l$ to $C_l$ for a given load growth rate $r$ , can be determined from

$$C_l = D_l \times (1+r)^{n_l} \tag{3-3}$$

where, $n_l$ is the number of years to reinforce and it can be derived from

$$n_l = \frac{\log C_l - \log D_l}{\log(1+r)} \tag{3-4}$$

It is assumed that reinforcement will occur when the circuit is fully loaded. Thus, investment will occur in $n_l$ years when the circuit utilisation reaches $C_l$. At this point, a duplication of the network component is taken as the required future investment.

If the power flow change along line $l$ is $\triangle P_l$ as the result of an additional withdrawal at node $N$ of $\triangle P_{In}$, this will bring forward future investment from $n_l$ to $n_{lnew}$, which can be calculated using (3-4) by replacing $D_l$ with $D_l$ + $\triangle P_l$.

The future investment can be discounted back to its present value, which will be a function of how far into the future the investment will be made. If a discount rate of $d$ is chosen, the present value of the future investment in $n_l$ and $n_{lnew}$ will be

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}} \tag{3-5}$$

$$PV_{lNew} = \frac{Asset_l}{(1+d)^{n_{lNew}}} \tag{3-6}$$

where, $Asset_l$ is the modern equivalent asset cost.

Then, the annualised incremental cost of the network component $l$ is the difference between the two present values of the future investment caused by $\triangle P_{In}$. Specifically, it is the change in the present values, multiplied by an annuity factor.

$$\begin{aligned} IC_l &= (PV_{lNew} - PV_l) \times annuityfactor \\ &= Asset_l \times \left(\frac{1}{(1+d)^{n_{lNew}}} - \frac{1}{(1+d)^{n_l}}\right) \times annuityfactor \end{aligned} \tag{3-7}$$

The LRIC to support node N will be the summation of the incremental cost over all supporting circuits, given by

$$LRIC_N = \frac{\sum_l IC_l}{\Delta P_{In}} \tag{3-8}$$

This charging model has been adopted by WPD in their EHV networks and two other main DNOs in the UK –UK Power Networks (UKPN) and CE electric are expected to take up this method in the near future. Other DNOs in the UK are also moving to more locational network charging models that take the key feature of the LRIC – change in time to reinforce of different system assets in different utilisation levels due to new nodal injection, FCP model[44].

The LRIC pricing can recognise the 'distance' that power must travel to meet demand as well as the degree of circuits' utilisation. Compared with the FCP model, LRIC can provide better locational signals as it gives charges for nodes rather than group.

### 3.4.4 Charging Model in HV/LV Distribution Networks

DRM is the methodology currently used for deriving network charges for HV/LV networks within Great Britain. The DRM model uses an approach outlined by [8] in 1977 for cost reflective retail tariffs in England and Wales. This model measures the investment costs of an additional 500MW of capacity and averages this cost across users connected to LV networks[9]. The investment costs are obtained from simulating a scaled down network instead of the actual network, without evaluating the real condition of the network.

The model is used to determine yardstick costs by customer class. The contribution of a customer group to peak demand is the method by which costs are divided between groups, taking into account diversity factors and load profile. The steps to calculate the yardstick cost are as follows:

1. Estimating the scaling factor between the system simultaneous maximum demand (SMD) and 500MW; SMD could be measured in the higher voltage level substations from the transmission system.

$$\mathrm{ScalingFactor} = \frac{500}{\mathrm{SMD}} \tag{3-9}$$

2. The '500 MW' model is obtained by multiplying the original system components' lengths or quantities at each voltage or transformation level as below.

$$\text{'500 MW' Model asset} = \text{System Asset} * \text{Scaling Factor} \tag{3-10}$$

where asset means different types of distribution asset, including overhead circuits, underground cables, transformers, switching gears etc.

3. Yardstick costs for each voltage or transformation level could be derived with diversity factor. Diversity factor is defined as the ratio of the sum of the individual maximum demand of the various parts of a distribution system to meet the system SMD, which is always greater than unity.

$$Yardstick_v = \frac{\sum_{asset=1}^{N} '500MW'Model}{500,000 \times Diversityfactor_v} \tag{3-11}$$

where $v$ is different voltage or transformation levels and N is the number of total assets at level v.

4. Taking losses into account, the cumulated cost at level D is calculated as follows.

$$CummulatedCost_D = \sum_{v \in D} (Yardstick_v \times (1 + Loss_v\%)) \tag{3-12}$$

where $Loss_v\%$ is percentage of loss at peak hours at level $v$ and $v$ is upstream voltage or transformation levels for calculating the cumulated cost at level $D$.

# 3.5 The Need to New Development of Charging Models in HV and LV Distribution Networks

In this section, the need to develop new charging models for HV and LV networks is addressed in two aspects. Firstly, the drawbacks of the current DRM model are described. Secondly, the reasons that the efficient charging models for EHV networks cannot be simply duplicated in HV and LV networks are explained.

## 3.5.1 Drawbacks of DRM

DRM is a simple postage stamp cost allocation approach. One major shortcoming of the DRM model is that the evaluated costs for 500MW capacity are simply scaled from the current existing asset costs without recognising the system assets utilisation. Hence, this model lacks cost reflectivity. Furthermore, the costs cannot reflect true forward looking investment costs as it doesn't take the future development into account but is based on the 'historic data'. Therefore, there is a need to develop a new charging methodology in order to provide cost reflective charges for HV and LV networks.

### 3.5.2 Infeasibility of FCP and LRIC in HV and LV Distribution Networks

As mentioned before, both LRIC and FCP for EHV networks require full AC load flow and contingency analyses to determine the more cost-reflective charges. However, network configuration in lower voltage levels networks is quite extensive. Therefore, replication of these two models would lead to a significant increase in the complexity and time of computation[6, 7].

In this circumstance, the separate FCP model for the HV/LV network was developed [6]. The procedures are similar to the one for EHV networks: estimating the future reinforcement costs and then allocating the costs across the expected demand. However, the difference to the model for EHV networks exists that the model simply scales up recent historic data on reinforcement costs without relying on the real network condition. Given that charges are to influence future behaviours, the investment costs in the determination of charges should be future network costs rather than historical costs. Historical costs are caused by the behaviours already made and therefore cannot be influenced by future charges. Therefore, it is necessary to develop new charging methodologies for HV/LV networks.

### 3.5.3 Desirable Features of New Charging Models for HV and LV networks

Based on the charging principles illustrated in the previous section in this chapter, it is desirable that the new charging models can involve the following features:

1. Cost reflectivity: charges should be derived on the basis of recognition of significant cost drivers by users;

    In order to achieve high level of cost reflectivity, cost drivers need to be assessed properly, which involves costs related with thermal capacity, voltage constraints, fault level limits and system security constraints [37]. The scope of this thesis is restricted to thermal and voltage constraints due to the following concerns:

i) Fault level related costs are mostly contributed by generation connection. This research only deals with demand charges whereas generation charges are out of scope. Therefore, fault level constraints are not considered in this thesis.

ii) Engineering Recommendation P2/6 mandates that customer's security levels depend on their sizes and the locations they are connected. High level security standards are strictly required for large users in EHV distribution networks and networks with upper voltage levels. Hence, N-1 and even N-2 contingency analysis are incorporated in network charging models in these networks. HV and LV networks operate radially with open points under normal condition, providing back-up facilities under any fault and allowing the shortest restoration and repair times at the same time. Under this circumstance, security driven costs are not considered in HV and LV distribution network charging models for simplicity purpose.

2. Forward-looking: the costs to be allocated should be future reinforcement costs rather than 'historic data';
3. Transparency: the charging models should utilise the publicly available data as far as possible;
4. Simplicity: the charging model should be easy to understand and follow.

In addition, it is inevitable that the trade-offs between these features in the models should be carefully reached.

In this thesis, separate charging models are developed for HV and LV networks, respectively. Detailed analysis is given in the following chapters.

# Chapter 4

# Evaluation of Investment Deferral Resulting from MGs on EHV Distribution Networks

## 4.1 Introduction

MG comes in various forms, ranging from solar PV, wind turbines, small hydro to solar water heating and among others. The governments in Europe see MG as a real alternative in reducing carbon emission and improving supply efficiency and security. Incentives for MGs are therefore on the rise, along with the number of units connected to the HV/LV distribution networks. These incentives typically bear no relation to the impact that MGs would have on the infrastructure network and on the generation supply. These un-directed incentives could bring unnecessary burdens to the energy system rather than help. Therefore, it is desirable to develop cost-effective incentives for MGs that can reflect the potential benefits/costs brought by MGs.

Investment deferral is considered one of the most important benefits brought by integrating MGs into distribution networks. It always refers to the deferment of network reinforcement by MGs that would otherwise be required to meet load growth[54].

As discussed in Chapter 2, evaluation of investment deferral resulting from DG has caused great attention from researchers. The appropriate evaluation of investment deferral can be translated into credits as incentives to guide efficient DG installation in distribution networks. As mentioned, the work carried out in these literatures mainly focuses on DG installation. In this chapter, the investment deferral is evaluated and quantified by connecting MGs at various locations and at differing penetration and concentration levels. This chapter aims to achieve three goals:

1. To propose a method to assess investment deferral resulting from MGs for the EHV network;
2. To investigate how investment deferral varies with different MG allocation approaches in the network;

3. To suggest a more effective allocation approach. It can bring more benefits to network investment deferral when the same quantity of MGs is connected. All the analyses are carried out on a subset of a practical system in the UK.

## 4.2 Investment Deferral Evaluation Method

The evaluation of the investment deferral makes use of changes to the present value of future investment consequent upon the addition of MGs connected at each node on a distribution network.

The mathematical formulation of the evaluation is described as follows:

$$\Delta PV = \sum_{l=1}^{M}(PV_l - PV_{lNew}) = \sum_{l=1}^{M}\left(\frac{Asset_l}{(1+d)^{n_l}} - \frac{Asset_l}{(1+d)^{n_{lNew}}}\right) \tag{4-1}$$

| | |
|---|---|
| $PV_l$ | Present Value of future investment without MG installation (current condition); |
| $PV_{lNew}$ | Present Value of the future investment with MG installation; |
| $\triangle PV$ | Change in present value, which could be regarded as either investment deferral or acceleration dependent on the direction of the change; |
| $M$ | Total number of asset in the network; |
| $d$ | Discount rate; |
| $Asset_l$ | Modern equivalent assets cost such as the costs of transformers and cables; |
| $n_l$ | Time to reinforce a network asset if no MG is installed; |
| $n_{lNew}$ | New time to reinforce a network asset if MG is installed; |

The value of $n_l$ can be determined from the current loading level and the assumed annual load growth rate $r$, as shown in (4-2) and (4-3):

$$C_l = D_l \times (1+r)^{n_l} \tag{4-2}$$

$$n_l = \frac{\log C_l - \log D_l}{\log(1+r)} \tag{4-3}$$

In (4-2), a network component (asset) $l$, such as a circuit, has a capacity of $C_l$, and supports a power flow of $D_l$, the time to reinforce the network asset is the number of year that it takes for the circuit to grow from $D_l$ to $C_l$ for a given load growth rate $r$. It is assumed that reinforcement will occur when the circuit is fully loaded. This assumption leaves out other cash flows that might benefit from an early investment, such as operational and maintenance costs. With the assumption, the present value of future reinforcement is given by (4-4).

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}} \tag{4-4}$$

If a group of MGs were installed in the network, the power flow in the supporting circuits would change, bringing the circuits' loading levels from $D_l$ to $D_{lNew}$. Using the same formula as the one in (4-2), the new time to reinforce the network, $n_{lNew}$, can be determined by (4-5)

$$n_{lNew} = \frac{\log C_l - \log D_{lNew}}{\log(1+r)} \tag{4-5}$$

Also the present value of the investment for the circuit l, when MGs are installed in the network, can be derived by (4-6) based on the new time to reinforce

$$PV_{lNew} = \frac{Asset_l}{(1+d)^{n_{lNew}}} \tag{4-6}$$

Assumption is made that the load grows at a similar rate over long-term, and the growth rate for every assets' power flow is therefore the same as the load growth rate.

## 4.3 Demonstration on a Practical System

In this section the proposed method for investment deferral evaluation is illustrated on a practical network, different allocation methods are implemented to demonstrate how investment deferral varies by MGs' locations, concentration and penetration levels.

It should be mentioned that this chapter aims at evaluating the impact of MGs on investment deferral for the EHV distribution network. Since MGs are usually connected at the HV/LV level of the distribution network, the installed MG units are aggregated to the EHV buses as a 'hypothetical' larger size DG. From there, the impacts of MGs on power flow reductions along EHV circuits are evaluated. According to this principle, the proposed method can also be used to evaluate the investment deferral brought by DGs which are directly connected into EHV distribution networks.

In this study, the following parameters are used for the purpose of analyses of investment deferrals:

1. Load growth rate is assumed as 1.6% per annum, which is the project long-term load growth rate in the UK[55];
2. A discount rate of 5.6% is the Minimum Acceptable Rate of Return set by the UK's gas and electricity markets regulator – Ofgem for the last price review period between 2005 and 2009.

### 4.3.1 Practical System

The 33kV distribution network in the city of Bath is chosen as the test network, and its single line diagram is shown in Figure 4-1. The network has a peak demand of 81MW and the load distribution at each node bus is shown in Figure 4-1.

Bath city has an approximate population of 90,000 and 38,000 households[56], each of which is considered as a possible candidate for a MG installation. In this study, MGs are regarded as micro-CHPs rated at 1.2kW, which can provide both heat and electricity together. The reason for choosing micro-CHP that the technology is the mature technology that is most likely to have large number of uptakes [57].

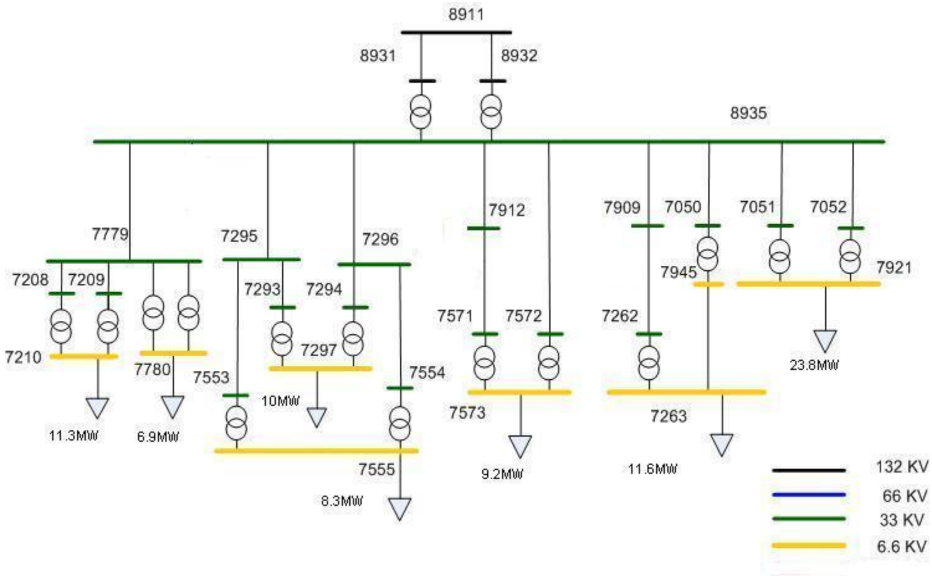


**Figure 4-1 Bath 33 kV Distribution Network**

By using the trend projected for the uptake of MGs in the UK government report [57], the number of micro-CHP units in Bath to be installed from 2010 to 2050 is derived as follows:

Firstly, the projected number of micro-CHP units in the UK is taken from the government report;

Secondly, the total household numbers in the UK and Bath City are obtained from census information and the growth rate of household numbers can be found from the UK household and population statistics [58];

Finally, according to the penetration rate of micro-CHP in the UK, the same rate is applied to Bath to derive the total number of micro-CHP units for the Bath 33kV network.

Another assumption is made to assume that there is only one micro-CHP could be installed in each household. Table 4-1 provides the projected number of micro-CHP units in the UK, the calculated number of units for Bath city with the support from market and government regulation and the total installed capacity.

**Table 4-1 Growth Rates of Micro-CHP for Bath City**

| Year | Number of units in the UK | Number of units in Bath | Total Installed Capacity (kWe) |
|---|---|---|---|
| Base year | 584 | 20 | 24 |
| 2010 | 333,333 | 921 | 1,105 |
| 2020 | 2,750,000 | 7,632 | 9,158 |
| 2030 | 6,666,667 | 18,617 | 22,340 |
| 2050 | 7,750,000 | 21,447 | 25,736 |

In this study, the projected number of micro-CHP units is grouped into four MG scenarios from the low penetration level to the high penetration level for the test system as shown in Table 4-2.

**Table 4-2 Four Scenarios of MG for this Study**

| Scenario | Number of Units | Total Installed Capacity (kWe) |
|---|---|---|
| I | 921 | 1,105 |
| II | 7,632 | 9,158 |
| III | 18,617 | 22,340 |
| IV | 21,447 | 25,736 |

### 4.3.2 Different MGs Allocation Approaches

Three potential MG allocation approaches are considered and analysed in this section, particularly in terms of their impacts on investment deferral of the 33kV Bath network for each of the above four scenarios. These three allocation approaches are discussed as follows:

1. MGs are evenly installed at load buses;

2. MGs are installed at load buses proportionally to the bus' loading level;

3. MGs are installed at load buses proportionally to nodal charges, which are calculated by a LRIC proposed in [5].

In each scenario of penetration level, it is assumed that the full capacity of 1.2kW of every Micro-CHP is taken all the time. Thereafter, the aggregated MGs capacity is regarded as a negative load in the corresponding bus-bar. Power flow analysis is carried out to evaluate the difference between the present values of future investment costs with and without MGs.

#### 4.3.2.1. **Even MGs Allocation**

With this allocation, the MGs in four different penetration levels are evenly allocated to load buses in the Bath 33kV network regardless of their load density. Table 4-3 gives the resulted capacity of MGs at each bus, increasing from 0.16MW at each bus in the lowest penetration level to 3.68MW in the highest penetration level.

**Table 4-3 Capacity of MGs in Each Bus – Even Allocation**

| Load Bus | Base Load (MW) | Allocated MGs Capacity (MW) | | | |
|---|---|---|---|---|---|
| | | Scenario I | Scenario II | Scenario III | Scenario IV |
| 7780 | 6.99 | 0.16 | 1.31 | 3.19 | 3.68 |
| 7297 | 10.01 | 0.16 | 1.31 | 3.19 | 3.68 |
| 7573 | 9.21 | 0.16 | 1.31 | 3.19 | 3.68 |
| 7263 | 11.60 | 0.16 | 1.31 | 3.19 | 3.68 |
| 7921 | 23.81 | 0.16 | 1.31 | 3.19 | 3.68 |
| 7555 | 8.33 | 0.16 | 1.31 | 3.19 | 3.68 |
| 7210 | 11.38 | 0.16 | 1.31 | 3.19 | 3.68 |

**Table 4-4 PV of Future Investment for Assets in Even MG Allocation**

| | Without MGs | With MGs in four Scenarios | | | |
|---|---|---|---|---|---|
| | | I | II | III | IV |
| Present Value (£) | 5,130,415 | 4,886,537 | 3,491,231 | 1,787,672 | 1,528,369 |

Table 4-4 shows the calculated present value of future investment because of even MG installation in the four MG penetration scenarios. Taken the present value of future investment without any MGs installed as a benchmark, it can be observed that the present value decreases down to £1,528,369 from the original £5,130,415 as the level of MG penetration in the network grows from without MGs to the highest penetration level of around a total of 25.7MW connected in the network. This is because as more MGs are connected to the system, there will be less power requirement from the upper stream networks, leading to lower utilisation and more spare capacity of system assets, which can delay the future investment.

#### 4.3.2.2. MGs Allocation in Proportion to Loading Levels

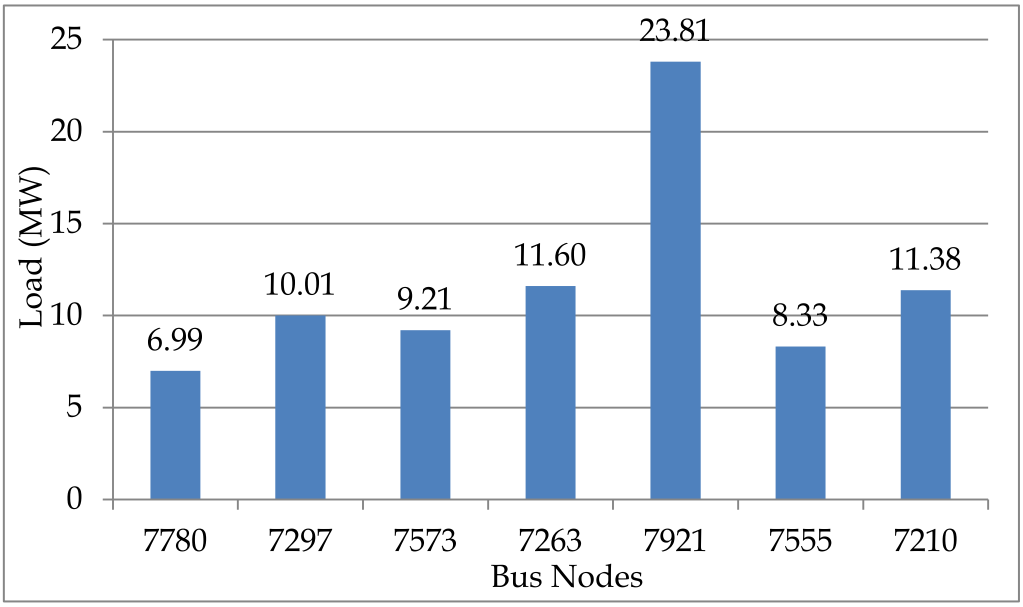


**Figure 4-2 Loading Level at Each Bus in the Bath 33kV Network**

Under this approach, MGs are allocated to load buses proportionally to the loading level of each bus. The loading level at each bus is illustrated in Figure 4-2.Moreover, the resulted capacities of MGs at each bus under the four penetration levels are given in Table 4-5. As shown, more MG units are allocated at the load buses with higher loading levels. Bus 7921 has the highest loading level of 23.81MW, hence the most MGs are allocated at the same bus in every scenario. In contrast, Bus 7780 has the least loading level of 6.99MW, therefore the smallest number of MGs is allocated at the same bus in every scenario.

**Table 4-5 Capacity of MGs in Each Bus – Proportional to Loading Levels**

| Load Bus | Base Load (MW) | Allocated MGs Capacity (MW) | | | |
|---|---|---|---|---|---|
| | | Scenario I | Scenario II | Scenario III | Scenario IV |
| 7780 | 6.99 | 0.09 | 0.79 | 1.92 | 2.21 |
| 7297 | 10.01 | 0.14 | 1.13 | 2.75 | 3.17 |
| 7573 | 9.21 | 0.13 | 1.04 | 2.53 | 2.92 |
| 7263 | 11.60 | 0.16 | 1.31 | 3.19 | 3.67 |
| 7921 | 23.81 | 0.32 | 2.68 | 6.54 | 7.53 |
| 7555 | 8.33 | 0.11 | 0.94 | 2.29 | 2.63 |
| 7210 | 11.38 | 0.15 | 1.28 | 3.13 | 3.60 |

**Table 4-6 PV of Future Investment for Assets in Proportion to Loading Levels**

| | Without MGs | With MGs in Four Scenarios | | | |
|---|---|---|---|---|---|
| | | I | II | III | IV |
| Present Value (£) | 5,130,415 | 4,771,645 | 2,954,784 | 1,149,392 | 918,014 |

Table 4-6 gives the present value of future investment with MGs installed proportionally to the loading levels. The overall trends are similar to the one in Table 4-4, with growing MG units installed in the network from scenario I to IV, the present value of future reinforcement decreases as assets' loading levels are decreasing. Moreover, it is not difficult to notice that despite the same penetration levels, the reduction in the present value is greater for MGs proportionally allocated to load levels than the one with even allocation approach. Taken scenario II as an example, the present value of future investment is £3,491,231 if MGs are allocated averagely at busbars in the network. The amount is however decreased down to £2,954,784 if MGs are allocated in proportion to loading levels in the network. This finding indicates that different allocation approaches for MGs in the network bring about different investment deferral benefits. Thus, an optimal allocation of MGs in terms of location and concentration levels to obtain the most benefits in terms of investment deferral for the network could be a meaningful study.

#### 4.3.2.3. **MGs Allocation in Proportion to Nodal Charges**

In this section, nodal charges are used to guide MGs' locational installation in the network. LRIC, developed by University of Bath in conjunction with WPD and Ofgem, has been chosen to derive nodal charges for the network. The reasons for the decision are discussed as follows.

1. LRIC nodal charges can reflect the extent of the use of network assets used and the degree of the assets' utilisation are able to provide better economical signal to guide the location of future generation and demand for improved network for efficiency[5].

2. It should be expected that customers who have to pay higher tariffs are more willing to install MGs to save more money than those who pay lower tariffs.

**Table 4-7 LRIC Charges for Test Network**

| Load Bus | LRIC charges(£/kW/year) |
|---|---|
| 7780 | 3.9 |
| 7297 | 2.2 |
| 7573 | 8.5 |
| 7263 | 28.5 |
| 7921 | 20.4 |
| 7555 | 5.8 |
| 7210 | 2.4 |

Table 4-7 provides the calculated LRIC prices for the test network. It can be seen from the table that the nodal prices at load bus 7263 and 7921 are much higher than that of the rest of nodes. This gives the information that customers connected to these two load buses use the network more extensively than customers connected at other nodes did. Therefore, it can be expected that if MG units are installed at these two nodes, benefits in terms of utilisation of network should be more significant than the rest of the nodes. Table 4-8 gives the resulted capacity of MGs in each busbar if they are allocated proportional to nodal charges. In each scenario, bus 7263 is allocated into the most capacity of MGs compared with the rest of busbars as it has the highest nodal charge indicated in Table 4-7.

**Table 4-8 Capacity of MGs in Each Bus – Proportional to Nodal Charges**

| Load Bus | Base Load (MW) | Allocated MGs Capacity (MW) | | | |
|---|---|---|---|---|---|
| | | Scenario I | Scenario II | Scenario III | Scenario IV |
| 7780 | 6.99 | 0.06 | 0.50 | 1.22 | 1.40 |
| 7297 | 10.01 | 0.03 | 0.29 | 0.70 | 0.80 |
| 7573 | 9.21 | 0.13 | 1.08 | 2.64 | 3.04 |
| 7263 | 11.60 | 0.44 | 3.64 | 8.88 | 10.22 |
| 7921 | 23.81 | 0.31 | 2.61 | 6.36 | 7.33 |
| 7555 | 8.33 | 0.09 | 0.73 | 1.79 | 2.06 |
| 7210 | 11.38 | 0.04 | 0.31 | 0.76 | 0.87 |

**Table 4-9 PV of Future Investment for Assets in Proportion to Nodal Charges**

| | Without MGs | With MGs in four Scenarios | | | |
|---|---|---|---|---|---|
| | | I | II | III | IV |
| Present Value (£) | 5,130,415 | 4,622,895 | 2,462,440 | 1,066,422 | 878,306 |

Similarly, the present values of future investment for assets with the MGs allocation in proportion to the nodal LRIC charges are shown in Table 4-9. The same trend is found that with increasing number of MGs into networks ranging from scenario I to scenario IV, the present value of future investment is reduced monotonously. From a comparison of the results in the above three allocation approaches, it can be seen that the present values reduction caused by MGs in this case are larger than that in any other allocation approach for MGs. Detailed comparison and analysis is discussed in the following section.

### 4.3.3 Comparison between Different MG Allocation Approaches

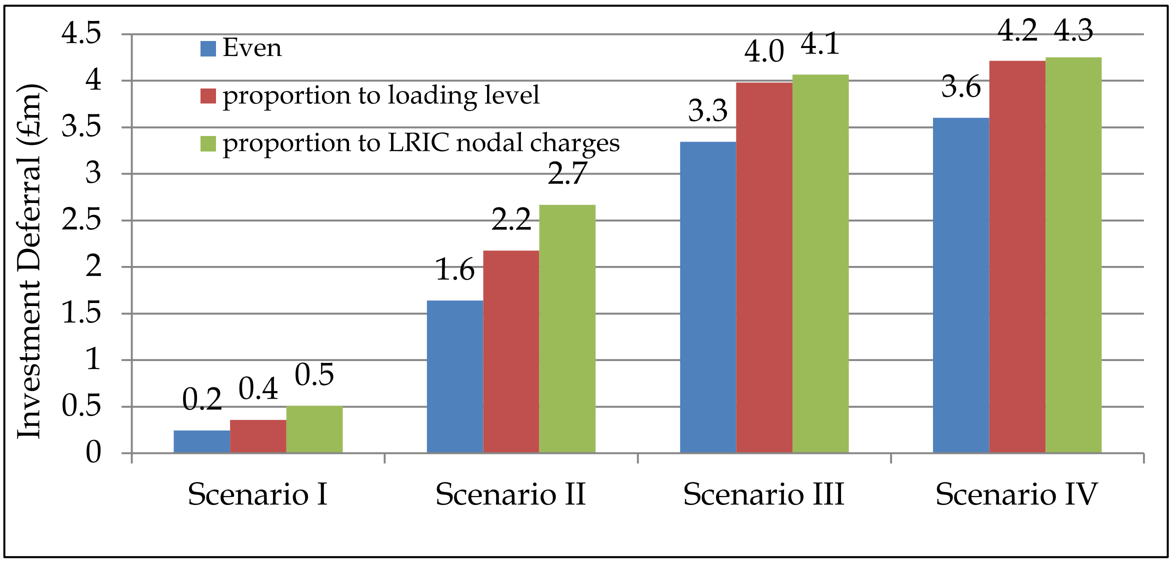


**Figure 4-3 Investment Deferral resulting from MGs Installation**

As introduced previously, investment deferral is recognised as the difference between the present values of future investment with and without MGs integration. Figure 4-3 illustrates the investment deferral brought by MGs integrating into the Bath 33kV network, considering the three MG allocation approaches and the four MG penetration levels. Overall, the location, penetration and concentration levels of MGs in the network can significantly affect investment deferral brought by MGs. As the MG penetration level increases from scenario I to scenario IV, the benefits in terms of network investment deferral grow correspondingly up to £4.3 million. For each penetration level, the most significant benefit is obtained by allocating MGs to the network proportionally to LRIC nodal charges. Taken scenario II as an example, MGs allocated averagely at busbars lead to the investment deferral of £1.6million only whereas an amount of £2.7million is reached if the same volume of MGs are allocated in proportion to nodal charges.

The findings can be explained that: LRIC nodal charges can recognise the network usage by customers, which results in higher charges for customers connected at highly utilised network whereas lower charges for the one connected at network with more spare capacity. In this case, if LRIC charges are used to guide the allocation of MGs, more MGs can be installed at the more highly utilised network to relieve the stress of networks more significantly and thus achieve the most benefits of investment deferral.

## 4.4 Chapter Summary

A method for evaluating investment deferral brought by integrating MGs into distribution networks has been presented in this chapter firstly. The method evaluates how MGs installed in the system can reduce the assets utilisation and defer future reinforcement. Connecting MGs at different location has brought about significantly different benefits. Furthermore, the concentration levels also affect investment deferral, which is demonstrated in this chapter by considering three MG allocation approaches. The results show that allocating MGs in proportion to LRIC nodal charges is more desirable as it brings the most benefits to network investment. The evaluation of benefits has provided the basis of the work in developing benefit-reflective economic incentives for MGs.

# Chapter 5

# Use of System Charges for HV Radial Distribution Networks

## 5.1 Introduction

Use of System charges are considered one of the effective ways to guide future demand and generation connection in distribution networks so as to encourage more efficient network usage and optimal network development. Presently, the DRM model is utilised for HV/LV distribution network pricing in the UK. As discussed earlier, the shortcoming of the DRM model is that it generates average charges at each voltage level, which can neither reflect the degree of use-of-system by customers nor provide locational signals to influence customers' behaviours. Therefore, the objective of the work in this chapter is to develop a new cost-reflective charging methodology for HV distribution networks. The features of the new proposed methodology exist in:

1. Charges are cost-based; the charges are derived by allocating future reinforcement costs among users by recognising their contribution into required future reinforcement activities. The future reinforcement activities are investigated in terms of thermal violation and voltage violation, respectively;
2. Charges are locational; Unlike uniform charges for every node at the same voltage level from the DRM model, charges from the new model can reflect the extent of use of network by customers, i.e. the more assets are used by users, the higher charges are given;

The proposed charging methodology is demonstrated on a simple HV network feeder and UK generic HV distribution networks.

## 5.2 Principle of Proposed Charging Model

The basic principle of the model is to allocate long term future reinforcement costs for upgrading distribution networks due to load growth among customers by reference to their contribution to the network upgrading activities. In this model, reinforcement activities are identified with a 10-year horizon, which is achieved by incrementing the loads, according to the projected load growth in each year provided by DNO's Long Term Development Statement (LTDS). The rationale for using a 10-year horizon is that it is consistent with LTDS growth assumption, yet load growth beyond 10 years might be highly uncertain. Furthermore, it is believed by industrialists that a 10-year horizon is an appropriate period to assess the required reinforcement costs and thus for network users to respond to the charges[6].

The flowchart of the proposed charging model is shown in Figure 5-1. Two reinforcement drivers, thermal violation and voltage violation, are assessed respectively and the corresponding reinforcement costs are quantified.

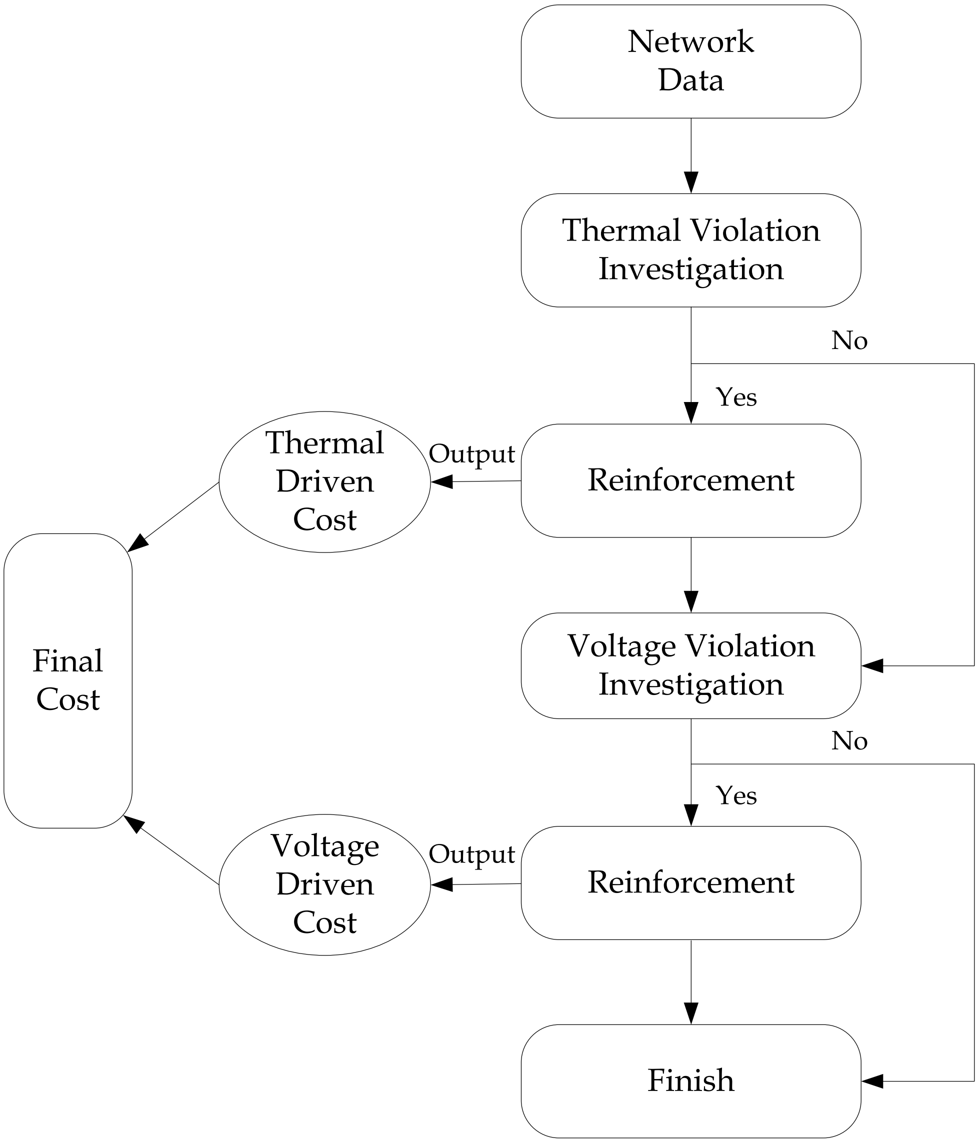


**Figure 5-1 Flowchart of Charging Model for High Voltage Networks**

Notably, when both of thermal and voltage violations happen on the feeder due to load growth, the reinforcement strategy in this study is to add additional circuits to solve thermal violation problem first. Then, voltage drop is examined afterwards as adding new circuits paralleled in upstream circuits can alleviate voltage problem to some extent. Moreover, the reinforcement strategy for resolving voltage problem is to add additional circuits in this study. It is understood that voltage control facilities such as on-load tap changers, are always used in HV distribution networks to maintain voltage drop within the allowed limits. However, in a long term prospective with load growth, voltage control facilities might not be able to maintain the voltage within the allowed limits and therefore upgrading existing circuits is necessary. Finally, the reinforcement costs are allocated among customers by reference to their contribution into the costs.

### 5.2.1 Reinforcement Activities Investigation

In a long term perspective, future reinforcement activities in HV distribution networks are mostly driven by either thermal violation or voltage violation because of load growth. In this section, an approach to investigate reinforcement activities is presented in terms of thermal driven and voltage driven, respectively.

Generally, under normal operating conditions HV networks are operated as a number of radial feeders with the facility of back-up interconnection, which only operates with the occurrence of a fault.

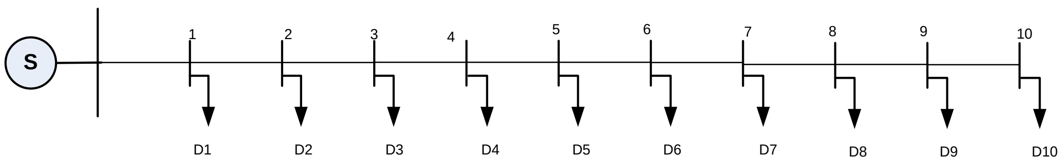


**Figure 5-2 An Example Feeder [59]**

For simplicity and demonstration purpose, a single feeder shown in Figure 5-2 is used to demonstrate the idea along with the following acceptable assumptions:

1. The same type of circuit is used in this feeder which means the parameters and capacity of the circuit are the same.
2. Study period is 10 years which indicates the cost recovery period.
3. Load growth rate at each node is assumed the same with each other in each year.

The detailed data for this feeder is given in Section 5.3.

#### 5.2.1.1. **Identification of Reinforcement Costs Driven by Thermal Violation**

The utilisation levels of each circuit of the feeder given in Figure 5-2 can be drawn in Figure 5-3, in which the circuit number is illustrated with sending and receiving buses, such as 0-1 and 1-2 etc. It should be noted that the assumption is made that each circuit has the same capacity. Therefore, the utilisation of the circuits decreases monotonously along with the reducing number of load they have to carry. If the same load growth rate is assumed at each node over a long term period, the new utilisation levels can be obtained as shown in Figure 5-3.

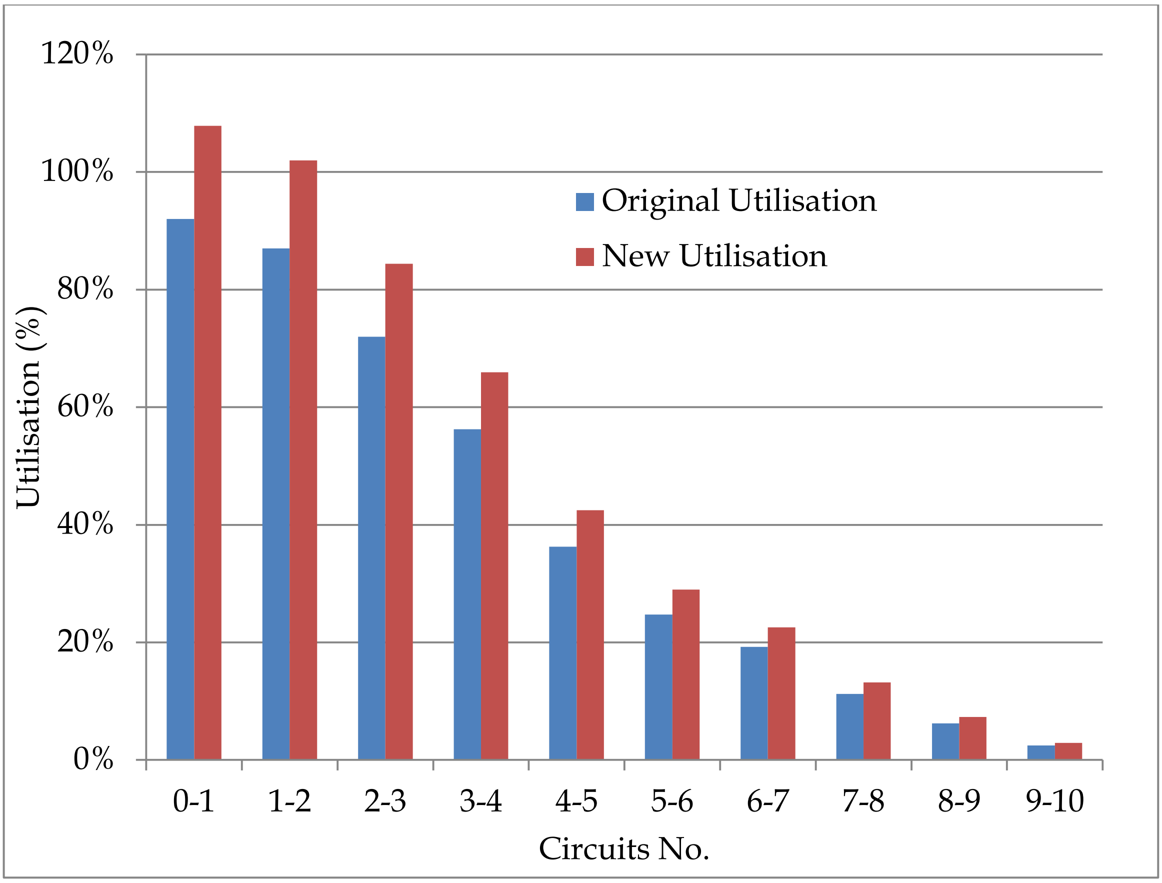


**Figure 5-3 Circuits' Utilisation in the Simple Feeder (Demonstration Only)**

Obviously the utilisation of circuits will be increased and therefore thermal violation might happen if the utilisation reaches 100%. One of the assumptions is made here that all feeders are assumed to be able to load to their full capacity as the security driven investment is not considered in the charging model in lower voltage networks. Another assumption is that losses are ignored in evaluating the utilisation of feeders. As seen in Figure 5-3, the first two circuits need to be reinforced by adding additional circuits due to thermal violation. In this case, the reinforcement costs can be calculated as $Cost_T$.

#### 5.2.1.2. Identification of Reinforcement Costs Driven by Voltage Violation

1. **Voltage Drop Calculation**

*1) Introduction of $K_{drop}$ factor*

To calculate voltage drop along feeders, $K_{drop}$ factor is employed in [60]. In this thesis, this approach is adopted to approximate the voltage drop in HV distribution feeders.

The $K_{drop}$ factor is defined as

$$K_{drop} = \frac{Percentage \;\; Voltage \;\; Drop}{kVA * km} \tag{5-1}$$

The $K_{drop}$ factor is determined by computing the percentage voltage drop down a line that is one kilometre long and serving a balanced three-phase load of 1kVA.

The voltage drop for the circuit that is 1km and serving a load of 1kVA with a power factor *cosφ* can be calculated using (5-2) firstly.

$$V_{drop\_unit} = (P * R + Q * X) / V = (1 * \cos\varphi * R + 1 * \sin\varphi * X) / V \tag{5-2}$$

where $R$ and $X$ are the resistance and reactance of 1km circuit; $V$ is the voltage level of the feeder in kV.

Thereafter, the $K_{drop}$ factor can be derived using (5-3):

$$K_{drop} = \frac{V_{drop\_unit}}{V} (perkVA * km) \tag{5-3}$$

where, $V$ is the voltage level of the feeder in volts.

Unique $K_{drop}$ factors can be determined for all standard conductors and voltages. Fortunately, most utilities will have a set of standard conductors and voltages. Therefore, a simple spread sheet program can be written that will compute the $K_{drop}$ factors for the standard configurations[60].

The $K_{drop}$ factor can be used to quickly compute the approximate voltage down a line section using (5-4).

$$V_{drop} = K_{drop} * \text{ kVA } * \text{ km} \tag{5-4}$$

The application of the $K_{drop}$ factor is not limited to computing the percentage voltage drop down just one line segment. When line segments are in cascade, the total percentage voltage drop from the source to the end of the last line segment is the sum of the percentage drops in each line segment.

*2) Validation of Utilising $K_{drop}$ factor: Compared with Detail Power Flow Calculation*

In order to validate the accuracy of voltage drop calculation using $K_{drop}$ *factor*, detailed power flow calculation is conducted, from which the result is compared with the approximation of voltage drop using $K_{drop}$ *factor*. The analysis is carried out in a three-segment feeder as shown in Figure 5-4 and the network data is given in Table 5-1 [60]. The impedance is 0.19+j0.39 Ω/km and power factor is 0.9.

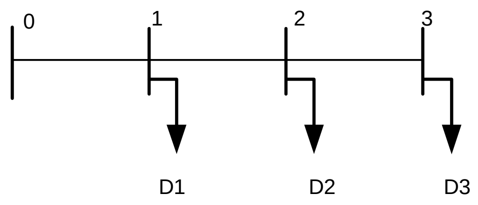


**Figure 5-4 Three-segment Feeder**

**Table 5-1 Network Data for the Three-segment Feeder**

| Sending bus | Receiving Bus | Load at Receiving Bus (kVA) | Length (km) |
|---|---|---|---|
| 0 | 1 | 300 | 2.41 |
| 1 | 2 | 750 | 1.21 |
| 2 | 3 | 500 | 0.8 |

By calculation, the $K_{drop}$ factor for the circuit in Figure 5-4 is 0.00035291. The resulted voltage drop in each segment of the feeder using $K_{drop}$ factor is given in Table 5-2. Meanwhile, detailed power flow analysis tool is used to calculate the detailed voltage drop in each segment of the feeder, given in Table 5-2 as a comparison. It can be noticed that the result from $K_{drop}$ factor method appears largely conforming with the one from detailed power flow calculation. Therefore, it is acceptable to use $K_{drop}$ factor to estimate voltage drop in this study. One of the key advantages of $K_{drop}$ factor method is its simplicity. More importantly, it can illustrate the 'contribution' of each network user into voltage drop and thus can be easily incorporated into the proposed charging model in this study. Detailed discussion is in the following subsection.

**Table 5-2 Comparison between $K_{drop}$ factor Method and Detailed Power Flow Method**

| Voltage Drop | $K_{drop}$ factor Method | Detailed Power Flow Method |
|---|---|---|
| $V_{d01}$ | 0.8025% | 0.8185% |
| $V_{d12}$ | 0.3308% | 0.3308% |
| $V_{d23}$ | 0.0882% | 0.0884% |
| Total $V_d$ | 1.2396% | 1.2377% |

2. **Identification of Reinforcement Costs**

For the radial feeder shown in Figure 5-2, the voltage drop can be calculated by the following equation (5-5).

$$\begin{aligned} V_{drop} &= V_{drop01} + V_{drop12} + \cdots + V_{drop910} \\ &= K_{drop} * (D_1 + D_2 + \cdots + D_{10}) * L_{01} + K_{drop} * (D_2 + \cdots + D_{10}) * L_{12} + \cdots + K_{drop} * D_{10} * L_{910} \\ &= K_{drop} * D_1 * L_{01} + K_{drop} * D_2 * (L_{01} + L_{12}) + \cdots + K_{drop} * D_{10} * (L_{01} + L_{12} + \cdots + L_{910}) \end{aligned} \quad (5\text{-}5)$$

It can be found that the 'contribution' of voltage drop from each load is determined by both the loading level and the distance to primary substation. Once voltage violation happens, adding or changing cables is always a solution to cope with the problem[61]. Therefore, the resulted reinforcement costs can thereby be estimated, as $Cost_V$.

## 5.2.2 Calculation of Unit Costs

### 5.2.2.1. **Unit Cost (Thermal)**

The first part of the unit cost consists in allocating the reinforcement costs driven by thermal violation among customers. It is proposed that the reinforcement costs $Cost_T$ should be allocated by reference to customers' 'contribution' to their reinforcement activities. Taking the simple feeder for example, the cost of reinforcing circuit0-1 should be allocated among all the 10 (D1 to D10) customers whereas the cost of reinforcing circuit1-2 should be allocated among customers from D2 to D9, regardless of customer D1. The total charge (the thermal driven part) for the year for each load is therefore obtained using (5-6).

$$Cost_{Ti} = \sum_{j=1}^{m} \frac{Cost_j * P_i}{\sum_{i=1}^{n} P_i} \tag{5-6}$$

where $m$ is the number of circuits needed to be reinforced; $n$ is the number of load using circuit $j$; $Cost_j$ is the cost of reinforcing circuit $j$ and $P_i$ is the load connected at bus $i$ .

The unit cost (the thermal driven part) for the customer at bus $i$ can be calculated using (5-7)

$$UnitCost_{Ti} = \frac{Cost_{Ti}}{P_i} \tag{5-7}$$

#### 5.2.2.2. **Unit Cost (Voltage)**

In this thesis, it is proposed that the reinforcement costs brought by voltage violation are allocated among customers in proportion to the product of its loading levels and distance to primary substation, *'P*L'*, at each node. The total charge (the voltage driven part) for the year for each load is therefore obtained using (5-8). Thereafter, the unit cost (the voltage driven part) for the customer at bus $i$ can be calculated using (5-9).

$$Cost_{Vi} = Cost_v * \frac{P_i * L_{0i}}{\sum_{i=1}^{t} P_i * L_{0i}} \tag{5-8}$$

$$UnitCost_{Vi} = \frac{Cost_{Vi}}{P_i} \tag{5-9}$$

where, $P_i$ is the load connected at bus $i$; $L_{0i}$ represents the distance to primary substation, $t$ is the number of load in the feeder.

In this case, the load which contributes more voltage drops will be charged more accordingly.

#### 5.2.2.3. **Final Unit Cost**

The final unit cost consists of the two parts of unit costs abovementioned, which are derived by voltage driven and thermal driven, respectively, as shown in (5-10).

$$UnitCost_{Final} = UnitCost_{Vi} + UnitCost_{Ti} \tag{5-10}$$

# 5.3 Demonstration on a simple feeder

## 5.3.1 Network Data

In this section, the proposed approach is demonstrated on the simple feeder illustrated in Figure 5-3. The network data such as circuit length and loading level is given in Table 5-3.

**Table 5-3 Information Data of the Simple Feeder**

| Sending bus | Receiving Bus | Load at Receiving Bus (kW) | Length (km) | Asset Costs(£) |
|---|---|---|---|---|
| 0 | 1 | 200 | 2.5 | 105750 |
| 1 | 2 | 200 | 3.1 | 131130 |
| 2 | 3 | 315 | 1.8 | 76140 |
| 3 | 4 | 400 | 3 | 126900 |
| 4 | 5 | 230 | 2.8 | 118440 |
| 5 | 6 | 110 | 3.5 | 148050 |
| 6 | 7 | 160 | 3.2 | 135360 |
| 7 | 8 | 100 | 2.6 | 109980 |
| 8 | 9 | 75 | 2 | 84600 |
| 9 | 10 | 50 | 1.6 | 67680 |

**Table 5-4 Typical Data for Circuits [62]**

| R (Ω/km) | X (Ω/km) |
|---|---|
| 0.219 | 0.286 |

All of the circuits have the same capacity, 2.1MVA. Unit asset cost is £42,300, which results in the asset cost for each circuit shown in Table 5-1. The typical data for the circuits is shown in Table 5-4[62]. The voltage level is mostly 11kV in the UK. The statuary limits of voltage is 11kV+/-6% in the UK [63]. Load growth rate is taken as 1.6% per year and power factor is 0.95.

## 5.3.2 Identification of Reinforcement Costs

### 5.3.2.1. **Thermal Driven Reinforcement Cost**

Under the original condition, the utilisation of circuits in the feeder can be calculated as shown in Figure 5-5. It can be observed that circuit 0-1 supporting the entire downstream load has the highest utilisation, around 90%. In contrast, circuit 9-10 has the lowest utilisation less than 10% because it only needs to carry load D10.

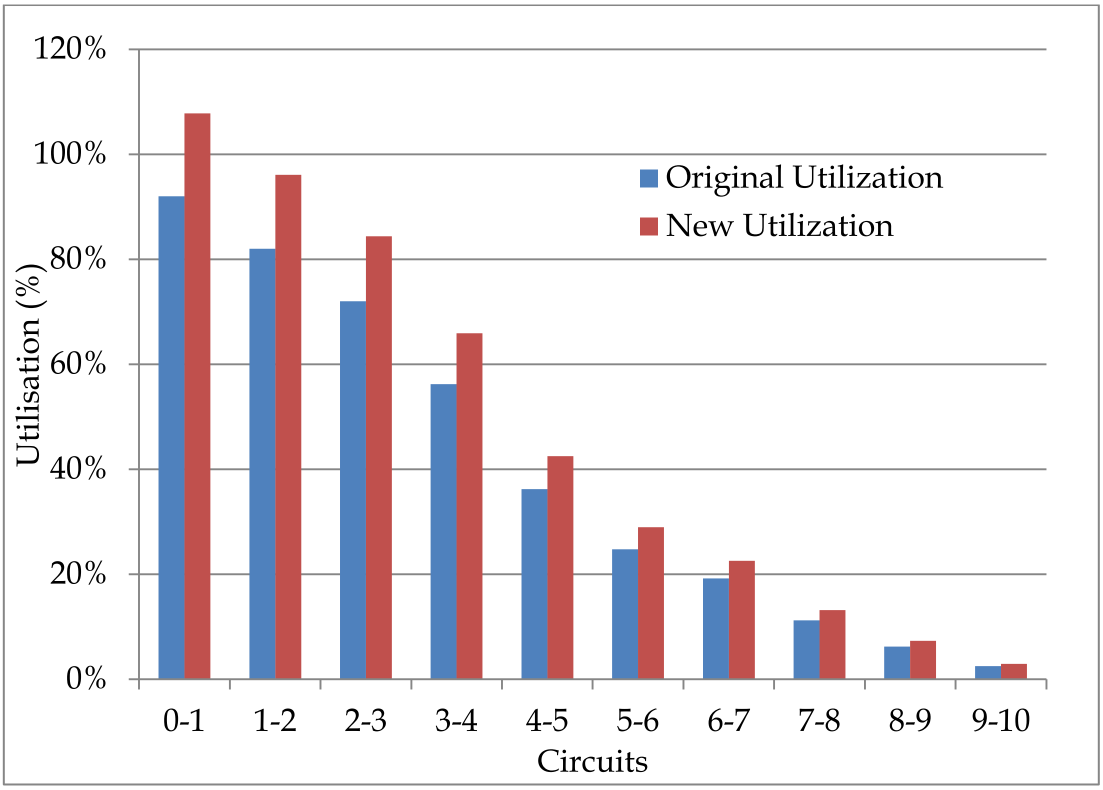


**Figure 5-5 Utilisation of Circuits in the Example Feeder**

Then, with load growth for a 10-year period, the utilisation levels of all the circuits increase. Notably, thermal violation appears in circuit 0-1 as the utilisation has exceeded 100% and therefore reinforcement is needed. Additional circuit is required to be added paralleled with circuit 0-1 to cope with the problem. Finally, the reinforcement costs are obtained as £105,750 by multiplying its length with the unit cost.

#### 5.3.2.2. **Voltage Driven Reinforcement Cost**

To calculate the $K_{drop}$ factor for the circuit in the simple feeder, 1kVA power with power factor 0.95 is carried by a 1km circuit. The obtained $K_{drop}$ factor is 0.00027 using the approach introduced in (5-3). In this case, the voltage drop along the feeder can be calculated accordingly using (5-4) and (5-5) and the result is illustrated in Figure 5-6.

In addition, the new voltage drop along the feeder due to load growth is shown in Figure 5-6 as well. It should be noted that here the new voltage drop is worked out after thermal problem is solved as suggested previously. This is to avoid overestimation of investment costs as the reinforcement for thermal violation can alleviate voltage problem to some extent.

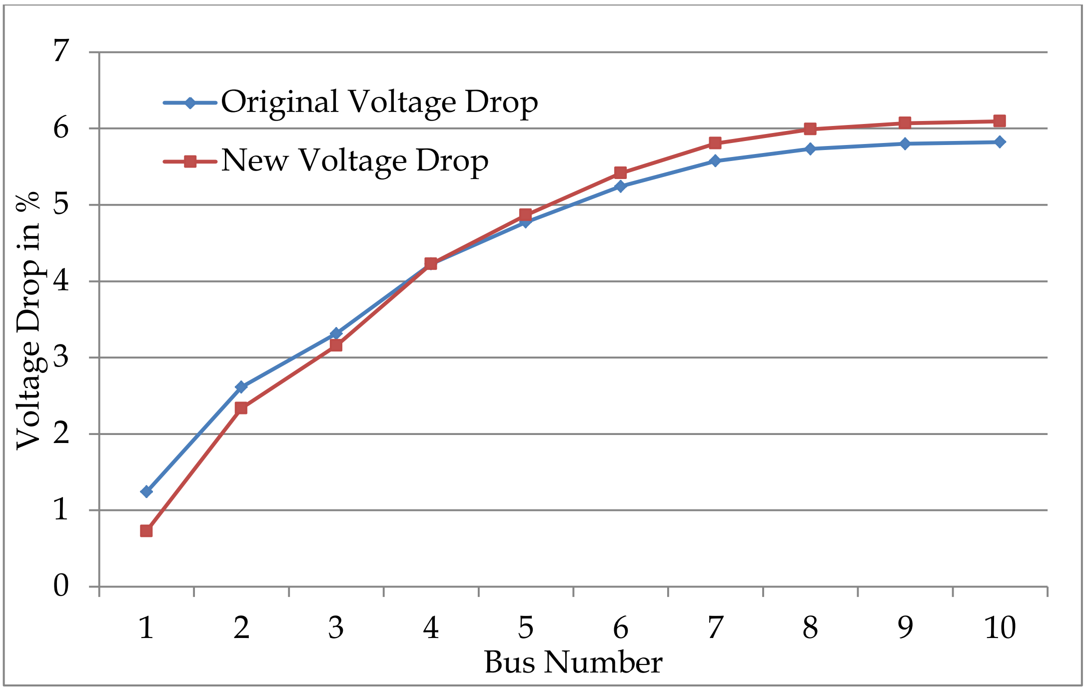


**Figure 5-6 Voltage Drop along the Sample Feeder**

According to [63], the voltage drop limit is 6% in the UK for HV distribution networks. It can be observed from Figure 5-6 that voltage violation occurs at Bus 9 and its downstream buses, due to load growth. The reinforcement is therefore needed to cope with the problem by adding additional circuits 8-9 and 9-10. Consequently, the reinforcement costs can be estimated as £152,280.

## 5.3.3 Unit Costs Calculation for the Simple Feeder

### 5.3.3.1. **Unit Cost (Thermal)**

The resulted costs should be allocated among the loads according to their usage of the circuits requiring reinforcement. Specifically in this case, the cost of circuit 0-1 should be allocated among all the downstream loads, i.e. from load D1 to load D10. Figure 5-7 indicates the load connected at each bus.

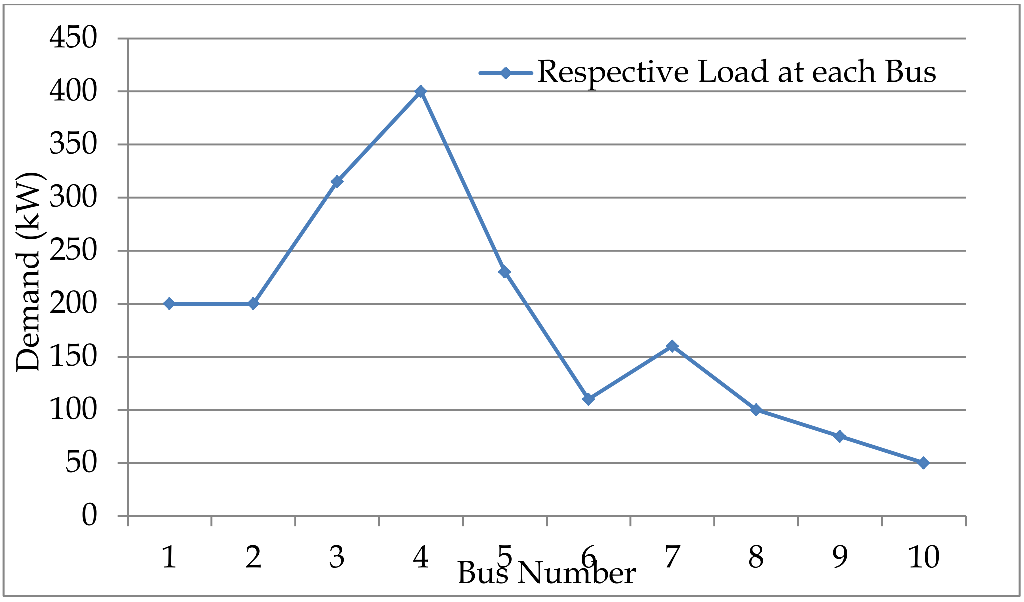


**Figure 5-7 Load at Buses in the Example Feeder**

Consequently, the total costs for the year resulted from thermal violation for all the nodes are assessed using (5-6) and illustrated in Figure 5-8.

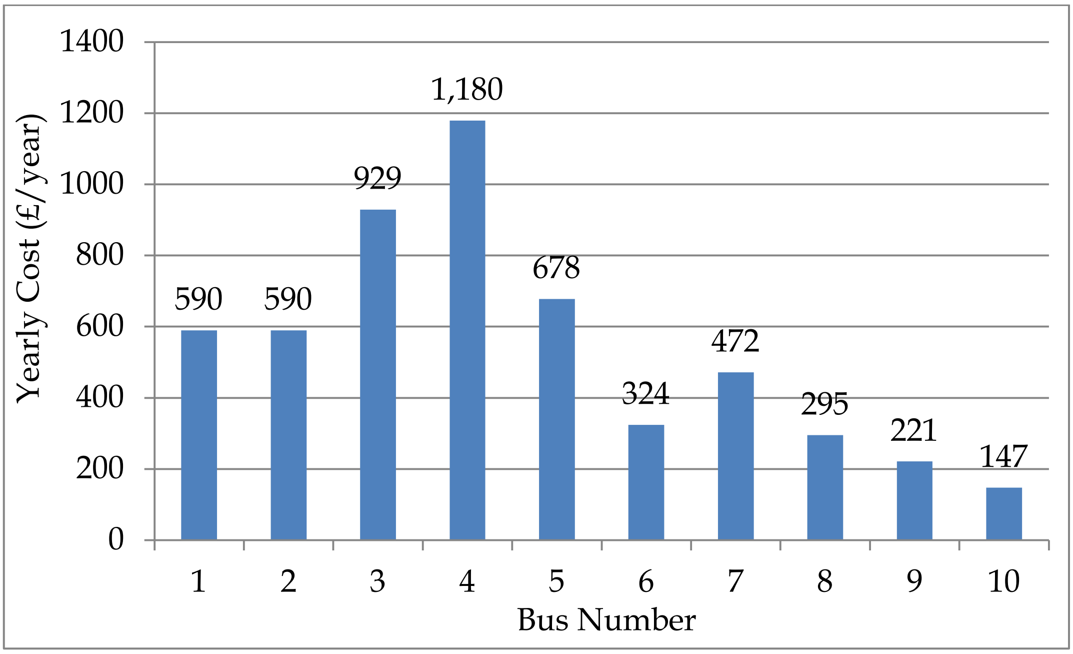


**Figure 5-8 Yearly Costs at Each Node (Thermal Driven)**

The results show, as expected, the total costs increase with the loading level. Load D4has the highest loading level among all the users and therefore are allocated with the highest yearly cost up to £1,180/year. In contrast, load D10 is allocated with the lowest year cost of £147/year as it has the least loading level as indicated in Figure 5-

7. This can again reflect the extent of use behind the proposed cost allocation method: the more they contributed into costs, the higher they are allocated with costs.

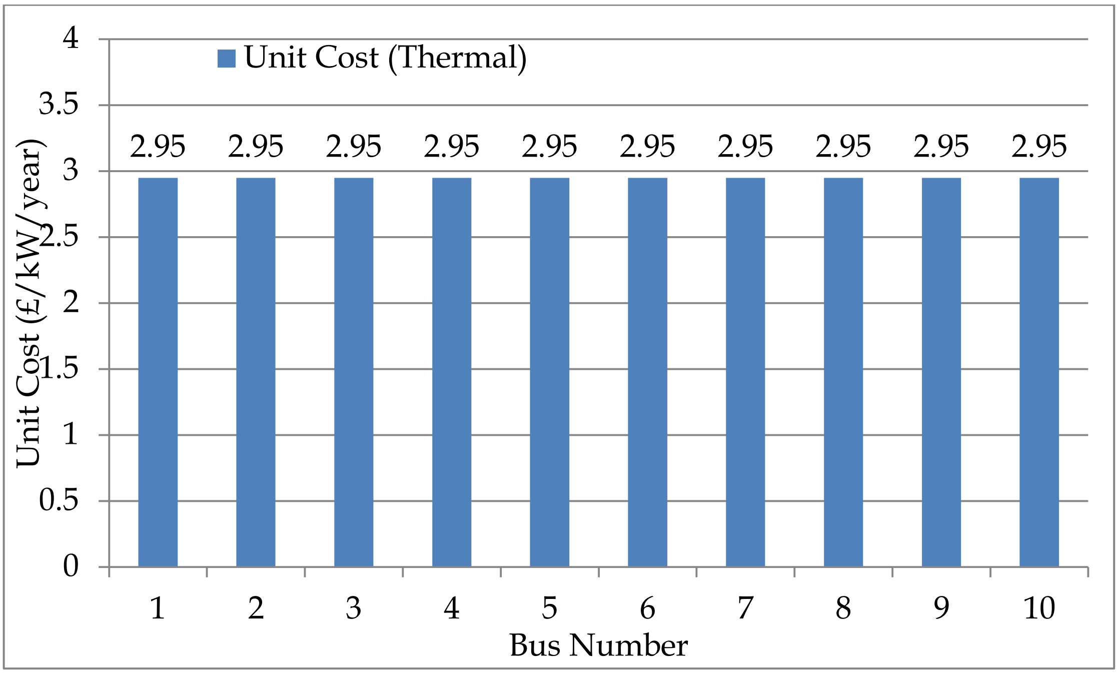


**Figure 5-9 Unit Costs (Thermal) for the Example Feeder**

Thereafter, the unit costs (£/kW/year) for customers connected are calculated using (5-7) and the results are shown in Figure 5-9. As observed, the unit costs all the nodes are the same as each other as £2.95/kW/year, reflecting the fact that all the loads are using circuit 0-1.

#### 5.3.3.2. **Unit Cost (Voltage)**

The charges for one year (£/year) driven by voltage violation for all the nodes are firstly calculated using (5-8) and the results are shown in Figure 5-10. Meanwhile, the voltage drop contributed by each load is calculated using (5-5) and drawn in Figure 5-11. It can be observed that load D4 has contributed the highest voltage drop, more than 1%, which results in the greatest total charge for load D4 as shown in Figure 5-10. In contrast, load D1 contributes into the least voltage drop and thus is allocated with the least cost driven by voltage violation. It can be concluded that the more voltage drop contributed, the higher charge is given for the load. This reflects the 'extent of use' philosophy behind the methodology: the greater the extent of use, the greater the charges will be.

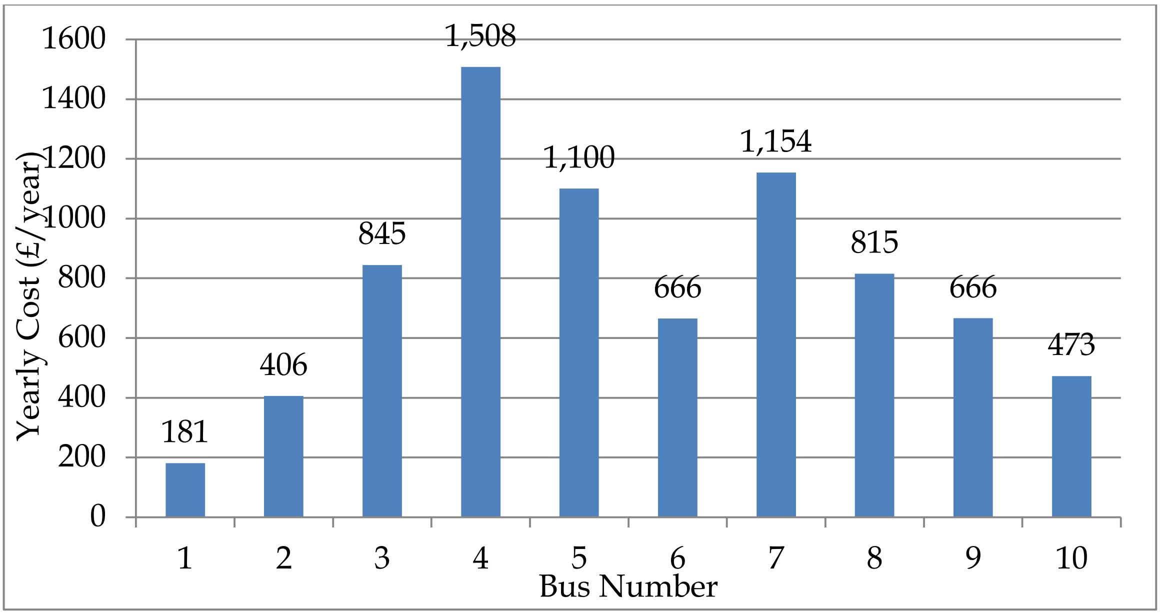


**Figure 5-10 Yearly Costs at Each Node (Voltage Driven)**

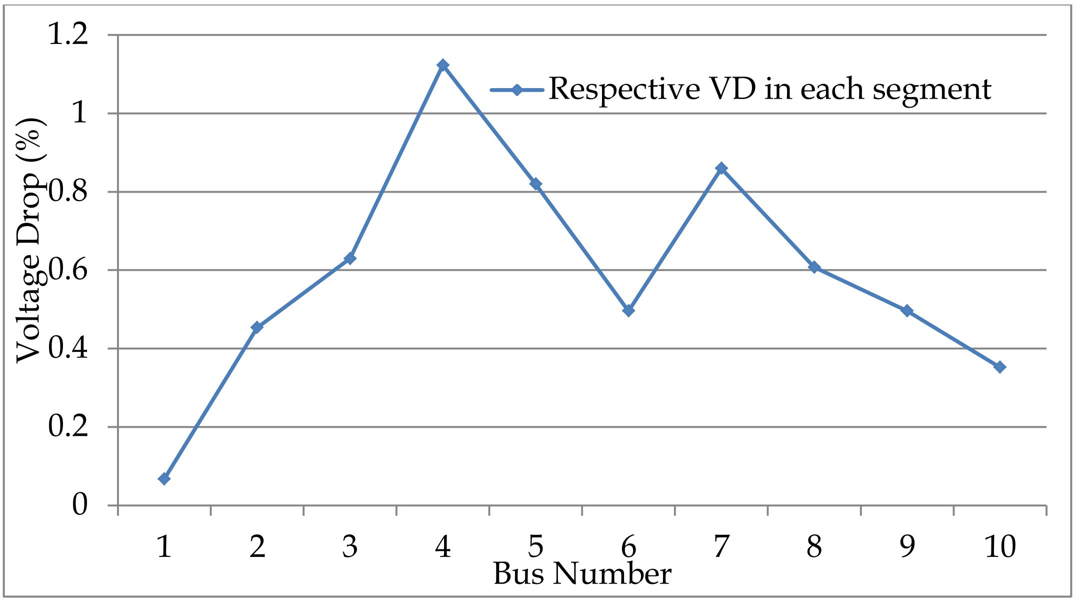


**Figure 5-11 Voltage Drop Contributed by Each Load**

Thereafter, the unit costs (£/kW/year) for customers connected are calculated using (5-9) as shown in Figure 5-12. Apparently, for a unit load the unit cost increase monotonously with the increasing distance, which the unit load must travel from. This is consistent with the 'extent of use' philosophy.

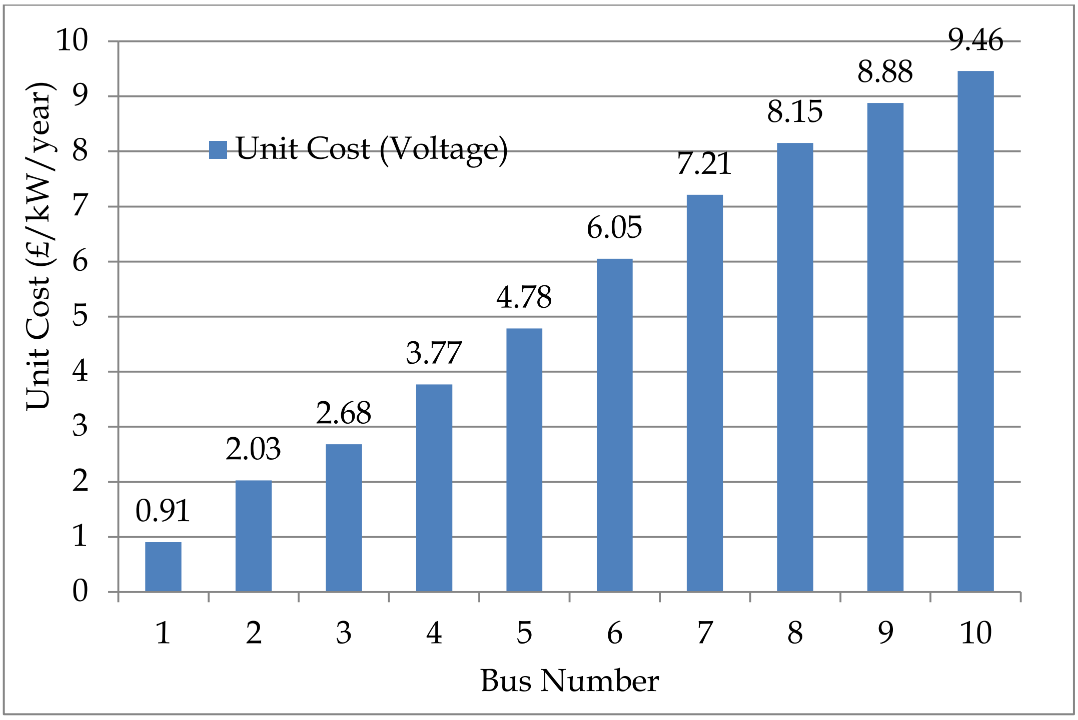


**Figure 5-12 Unit Costs (Voltage) for the Simple Feeder**

#### 5.3.3.3. Unit Cost (Final)

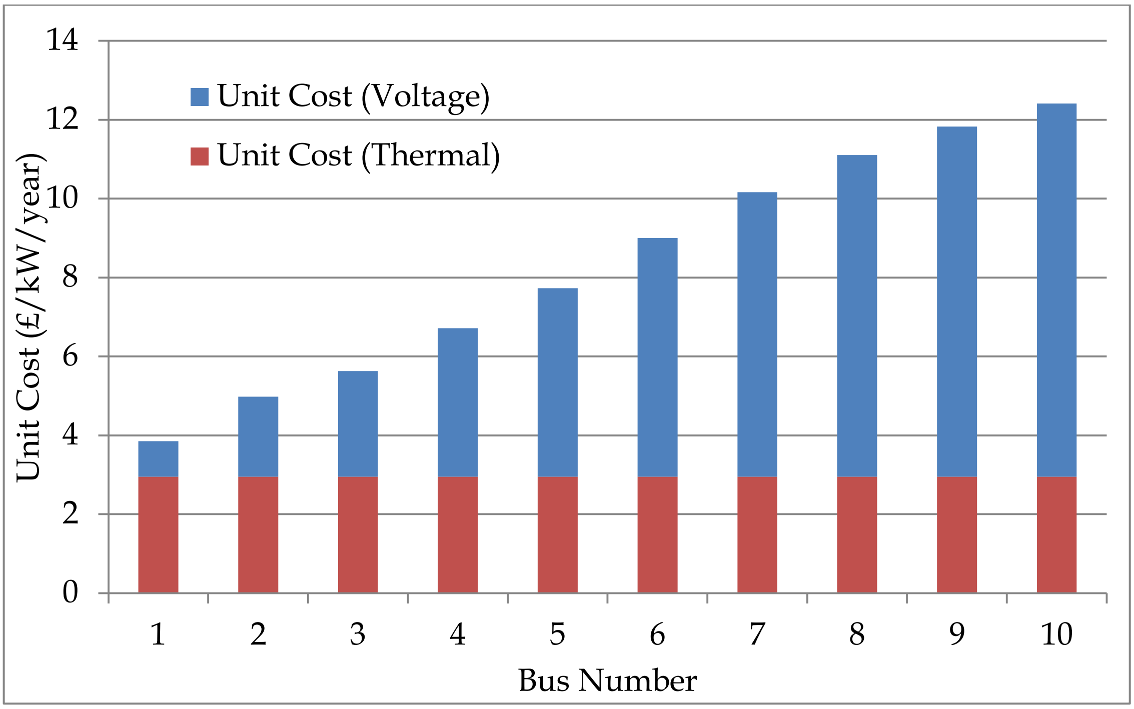


**Figure 5-13 Final Unit Costs for the Example Feeder**

Overall, the final unit costs for all the nodes can be obtained using (5-10) by adding the two parts of unit costs up together. The results are illustrated in Figure 5-13. It can be observed that in this example, voltage driven cost dominate over the thermal driven cost.In addition, the unit cost for load D1 is the least as the unit power at this location uses the least asset and contributes into the smallest reinforcement cost.

## 5.4 Demonstration on a UK Generic HV Network

In this section, the proposed charging approach is demonstrated on one of the UK generic high voltage distribution networks as shown in Figure 5-14[64]. The network is an 11kV urban network fed from a 33kV supply point, including 8 feeders with different length of circuits, serving 75 loads in total.

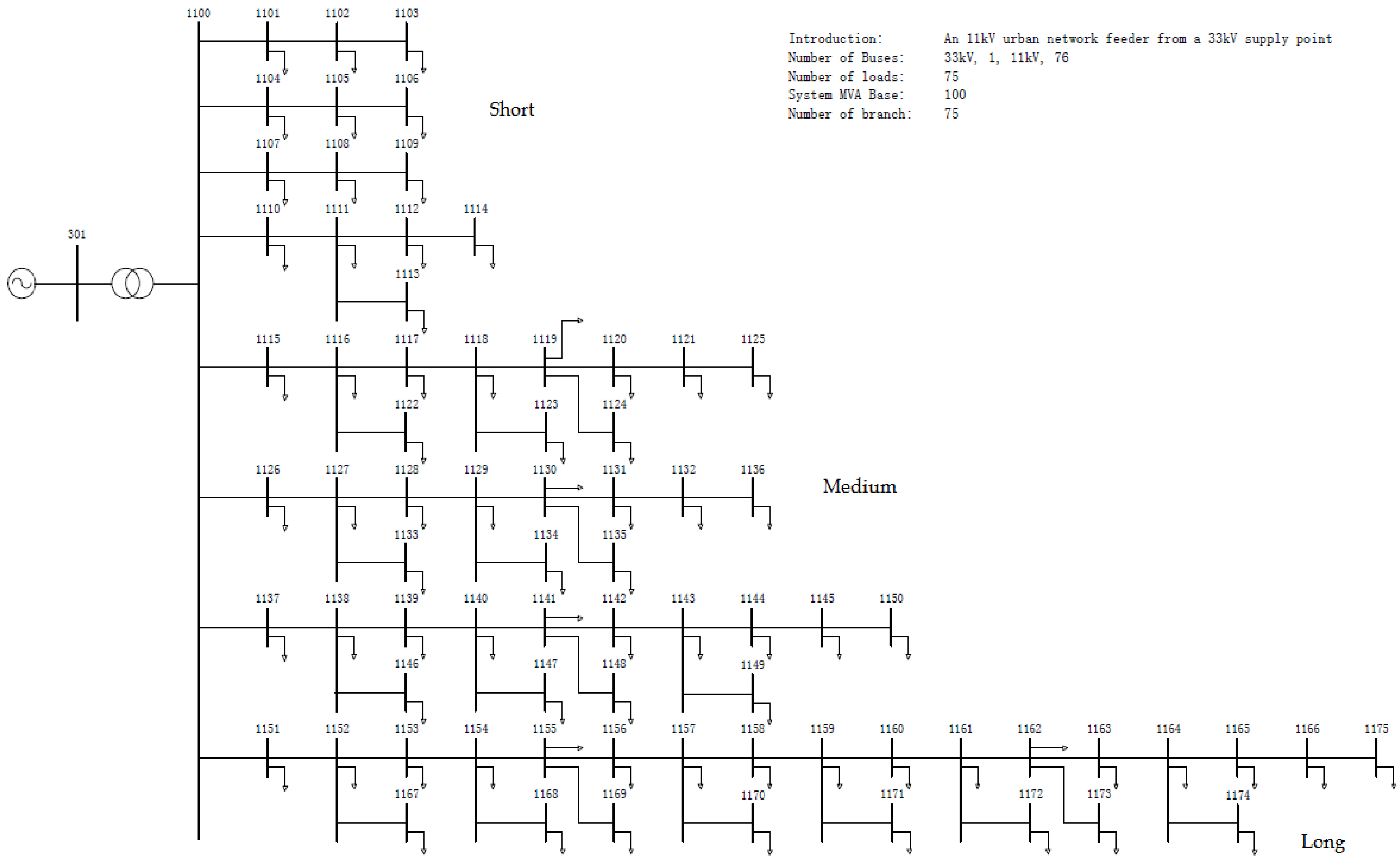


**Figure 5-14 A Generic High Voltage Network for the UK Distribution System**

For simplicity, charges for three feeders with typical length are calculated, shown in Figure 5-14 as short, medium and long.

### 5.4.1 Charges for the Short Feeder in the Generic Network

For the 'short' feeder shown in Figure 5-14, there are 3 buses cascaded connected. The data for the 'short' feeder is given in Table 5-5.

**Table 5-5 Network Data for the 'Short' Feeder**

| Circuit No. | From Bus | To Bus | Load at Receiving Bus (kVA) | Length (km) | Rating (MVA) |
|---|---|---|---|---|---|
| 1 | 1100 | 1107 | 400 | 1.504 | 4.84 |
| 2 | 1107 | 1108 | 400 | 1.504 | 4.84 |
| 3 | 1108 | 1109 | 118 | 0.236 | 4.84 |

Under a load growth rate 1.6% per year within 10 years, the utilisation of circuits and voltage drop along the 'short' feeder are respectively illustrated in Figure 5-15 and 5-16. Obviously, no reinforcement activities driven either by thermal violation or voltage violation are necessary under a load growth rate 1.6% per year within 10 years. Therefore, no charges will be given for the loads connected in this feeder.

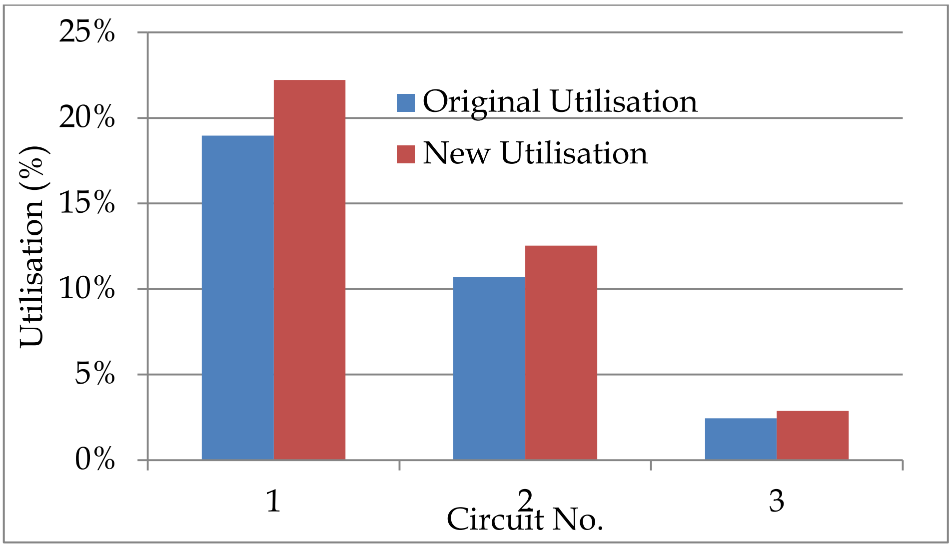


**Figure 5-15 Utilisation of Circuits in the 'Short' Feeder**

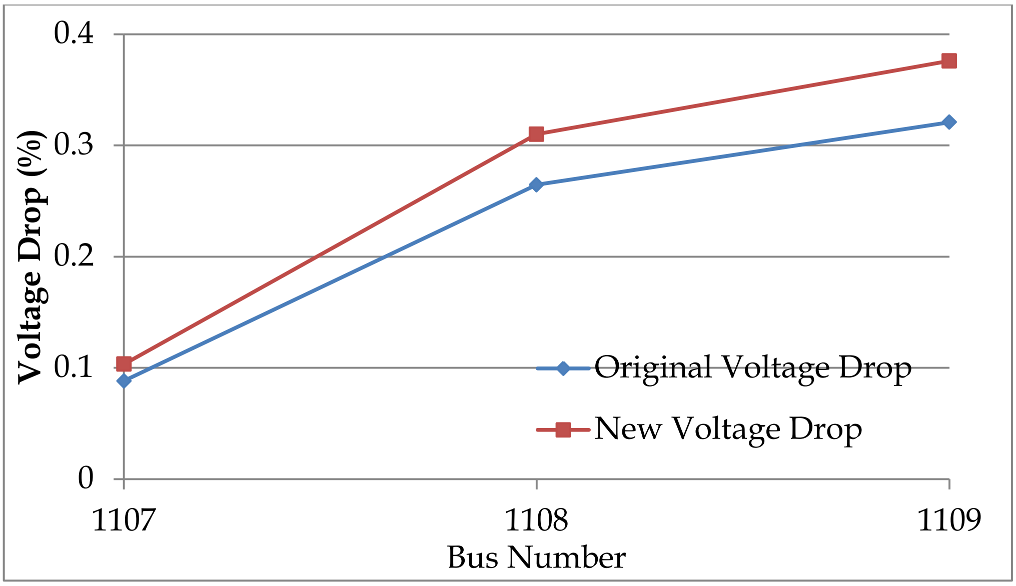


**Figure 5-16 Voltage Drop in the 'Short' Feeder**

### 5.4.2 Charges for the Medium Feeder in the Generic Network

For the 'medium' feeder shown in Figure 5-14, there are 8 main cascaded buses with 3 side-branches connected. The load and circuit information are given in Table 5-6. The asset cost is 82,900£/km. Under a load growth rate 1.6% per year within 10 years, reinforcement costs are forecasted and unit costs are drawn for loads.

**Table 5-6 Network Data for the 'Medium' Feeder**

| Circuit No. | From Bus | To Bus | Load at Receiving Bus (kVA) | Length (km) | Rating (MVA) |
|---|---|---|---|---|---|
| 1 | 1100 | 1126 | 868 | 0.902 | 8.86 |
| 2 | 1126 | 1127 | 868 | 0.902 | 8.86 |
| 3 | 1127 | 1128 | 868 | 0.902 | 8.86 |
| 4 | 1128 | 1129 | 868 | 0.902 | 8.86 |
| 5 | 1129 | 1130 | 868 | 0.902 | 8.86 |
| 6 | 1130 | 1131 | 868 | 0.902 | 8.86 |
| 7 | 1131 | 1132 | 868 | 0.902 | 8.86 |
| 8 | 1132 | 1136 | 436 | 0.902 | 8.86 |
| 9 | 1127 | 1133 | 432 | 0.205 | 4.84 |
| 10 | 1129 | 1134 | 432 | 0.205 | 4.84 |
| 11 | 1130 | 1135 | 436 | 0.205 | 4.84 |

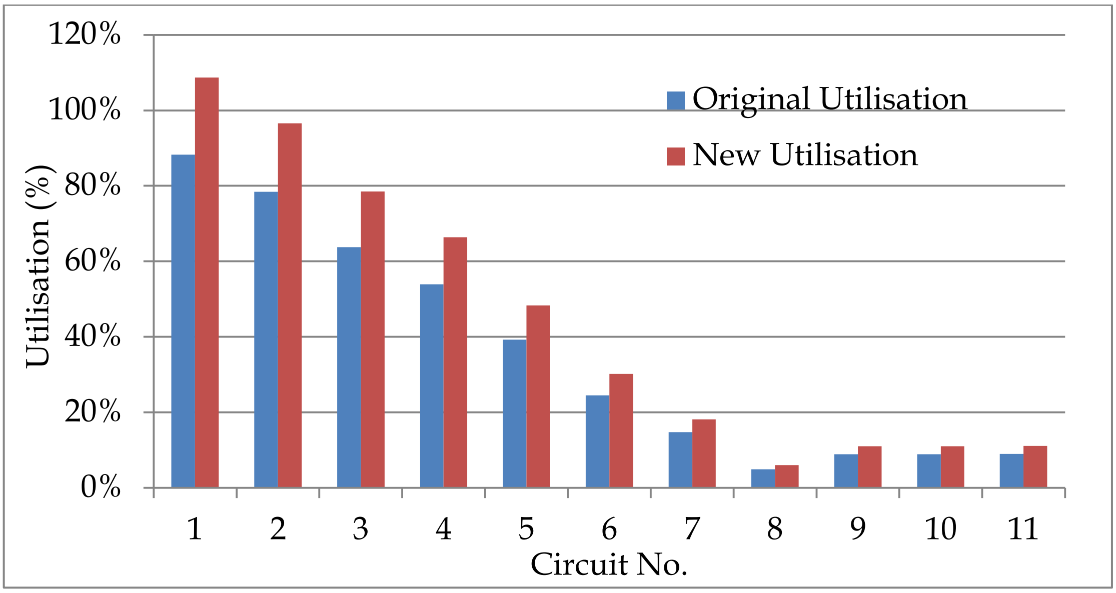


**Figure 5-17 Utilisation of Circuits in the 'Medium' Feeder**

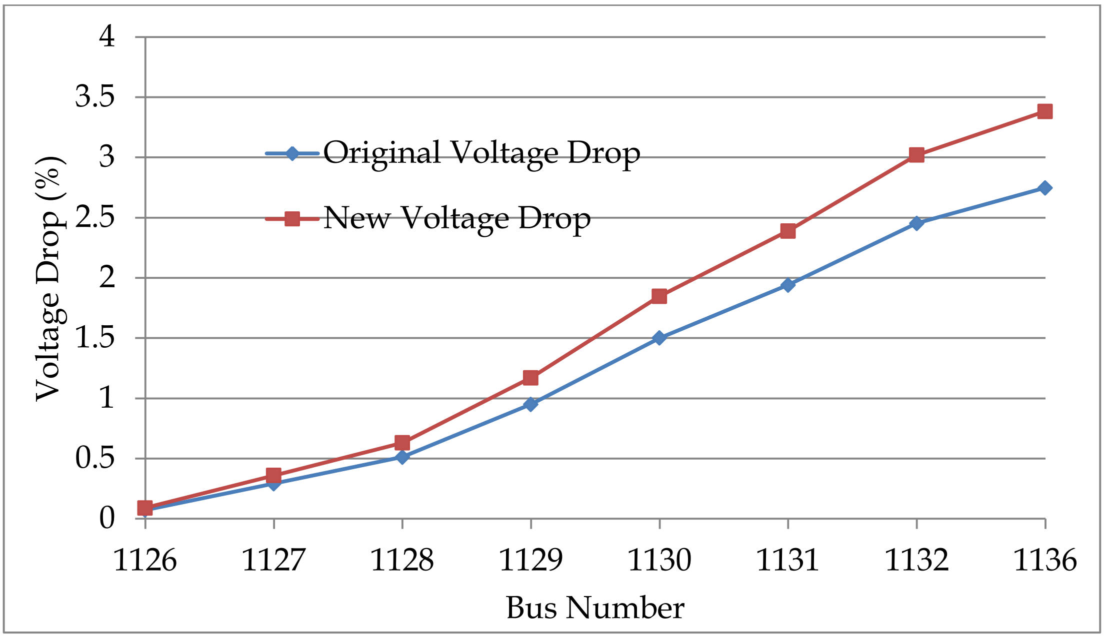


**Figure 5-18 Voltage Drop in the 'Medium' Feeder**

It should be noted that the loads, which are connected at the feeder through the 3 side-branches, are aggregated into the main bus when doing the reinforcement activities investigation. For example, the effective load at bus 1127 includes the load at bus 1133. The same condition exists in load at bus 1129 and 1130, which include load at bus 1134 and 1135, respectively. Thereafter, thermal and voltage driven reinforcement activities are both investigated and illustrated in Figure 5-17 and 5-18.

In this case, no reinforcement costs driven by voltage violation are identified due to load growth. For thermal driven investigation, the circuit 1 (1100-1126) has reached its rating due to load growth and therefore reinforcement is required. By multiplying unit asset cost with its length, the total reinforcement cost is identified as £74775.8. Thereafter, the unit costs for customers connected at the 'medium' feeder are worked out using (5-7), as shown in Figure 5-19. The unit cost at each node is the same with each other indicating the fact that circuit 1 (1100-1126) supports all the users in the feeder.

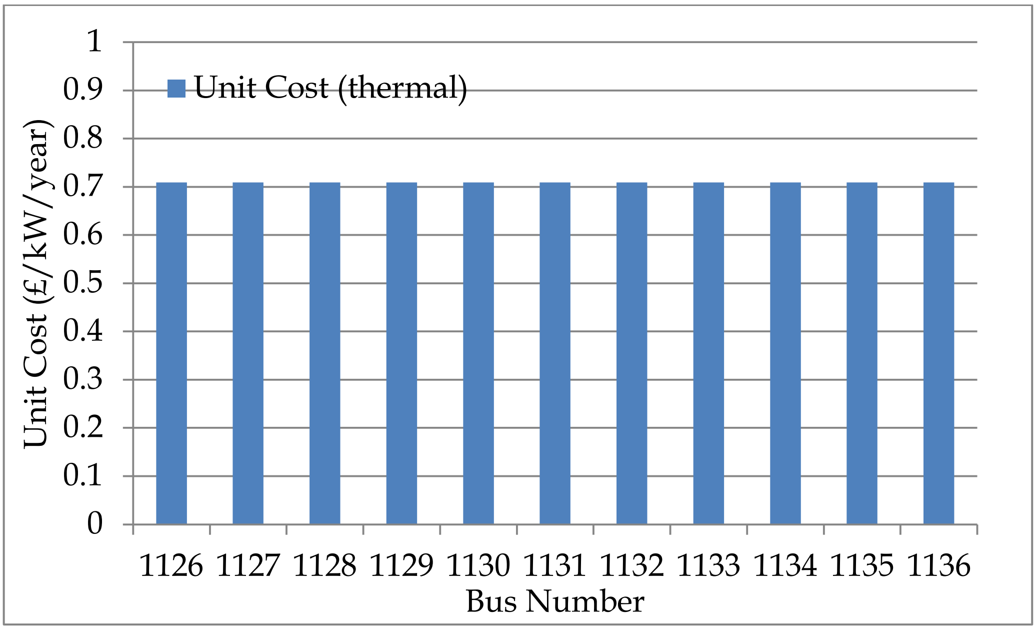


**Figure 5-19 Unit Costs for the 'Medium' Feeder**

### 5.4.3 Charges for the Long Feeder in the Generic Network

For the 'long' feeder shown in Figure 5-14, there are 17 main cascaded buses with 8 side-branches connected. The load and circuit data are given in Table 5-7. The asset cost is 82,900£/km. Under a load growth rate 1.6% per year within 10 years, reinforcement costs are forecasted and unit costs are drawn for loads.

Table 5-7 Network Data for the 'Long' Feeder

| Circuit No. | From Bus | To Bus | Load at Receiving Bus (kVA) | Length (km) | Rating (MVA) |
|---|---|---|---|---|---|
| 1 | 1100 | 1151 | 349 | 0.805 | 8.86 |
| 2 | 1151 | 1152 | 349 | 0.805 | 8.86 |
| 3 | 1152 | 1153 | 351 | 0.805 | 8.86 |
| 4 | 1153 | 1154 | 351 | 0.805 | 8.86 |
| 5 | 1154 | 1155 | 351 | 0.805 | 8.86 |
| 6 | 1155 | 1156 | 351 | 0.805 | 8.86 |
| 7 | 1156 | 1157 | 351 | 0.805 | 8.86 |
| 8 | 1157 | 1158 | 351 | 0.805 | 8.86 |
| 9 | 1158 | 1159 | 351 | 0.805 | 8.86 |
| 10 | 1159 | 1160 | 351 | 0.805 | 8.86 |
| 11 | 1160 | 1161 | 351 | 0.805 | 8.86 |
| 12 | 1161 | 1162 | 351 | 0.805 | 8.86 |
| 13 | 1162 | 1163 | 351 | 0.805 | 8.86 |
| 14 | 1163 | 1164 | 351 | 0.805 | 8.86 |
| 15 | 1164 | 1165 | 351 | 0.805 | 8.86 |
| 16 | 1165 | 1166 | 351 | 0.805 | 8.86 |
| 17 | 1166 | 1175 | 226 | 0.805 | 8.86 |
| 18 | 1152 | 1167 | 226 | 0.276 | 4.84 |
| 19 | 1154 | 1168 | 228 | 0.276 | 4.84 |
| 20 | 1155 | 1169 | 228 | 0.276 | 4.84 |
| 21 | 1157 | 1170 | 228 | 0.276 | 4.84 |
| 22 | 1159 | 1171 | 228 | 0.276 | 4.84 |
| 23 | 1161 | 1172 | 228 | 0.276 | 4.84 |
| 24 | 1162 | 1173 | 228 | 0.276 | 4.84 |
| 25 | 1164 | 1174 | 228 | 0.276 | 4.84 |

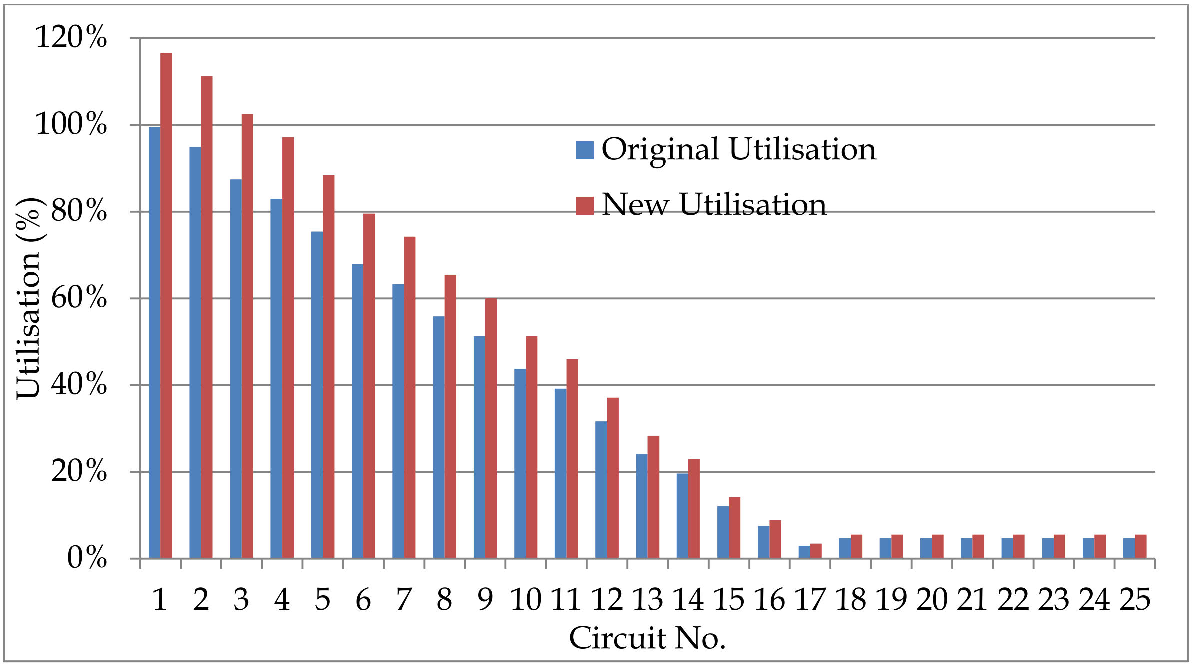


**Figure 5-20 Utilisation of Circuits in the 'Long' Feeder**

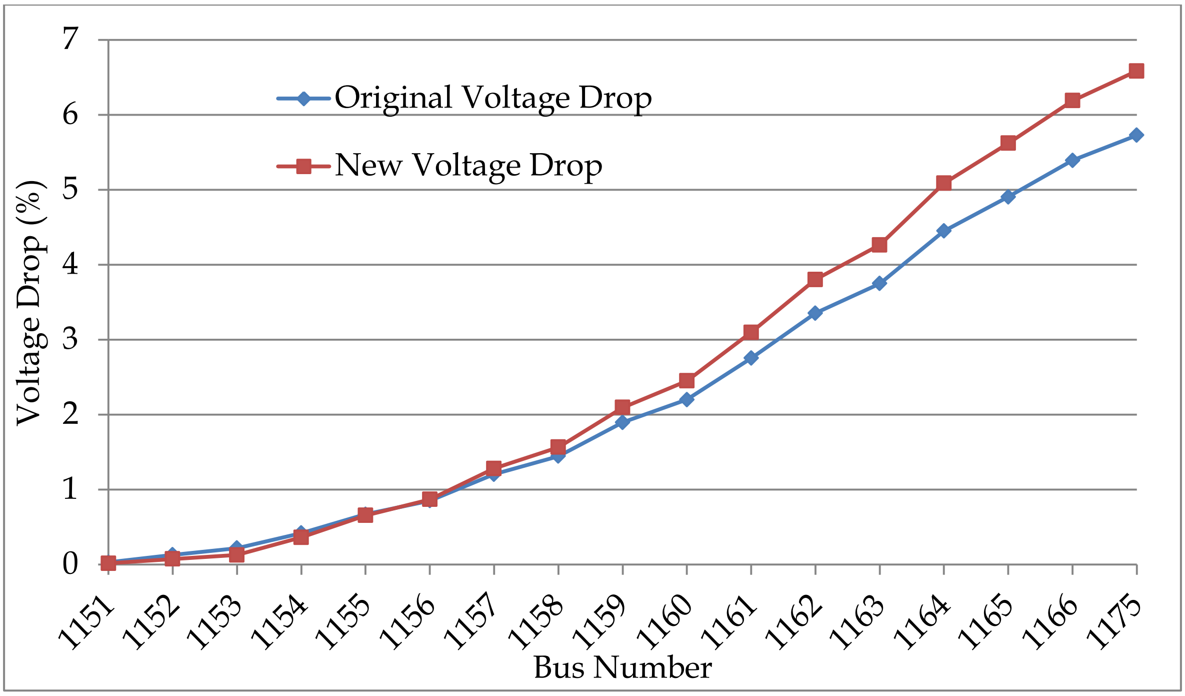


**Figure 5-21 Voltage Drop in the 'Long' Feeder**

For thermal driven reinforcement as shown in Figure 5-20, three circuits no. 1, 2 and 3 (1100-1151; 1151-1152 and 1152-1153) are identified as reaching their rating due to load growth and therefore require reinforcement. The total costs are £200,203.5. Again, by using (5-6) and (5-7), unit costs for load are illustrated in Figure 5-22. As seen, Load at Bus 1151 has the lowest unit cost driven by thermal, followed by load at Bus 1152 and 1167. The load at the rest of buses share higher unit costs. This is because load at Bus 1151 only use circuit 1100-1151, whereas load at 1151 and 1167 use circuits 1100-1151 and 1151-1152. The rest of loads use all of the three circuits.

For voltage driven reinforcement investigation as shown in Figure 5-21, voltage violation happens at bus 1166 and 1175. Thereafter, the voltage driven costs are identified as £133,469. By using (5-8) and (5-9), unit costs driven by voltage violation for load are also shown in Figure 5-22. It can be observed that the unit costs are highly related to distance for which the load must travel: the further from primary substation, the more unit cost given. It can be explained that voltage drops are determined by loading level and length. For cost unit power (per kW), it is only determined by distance.

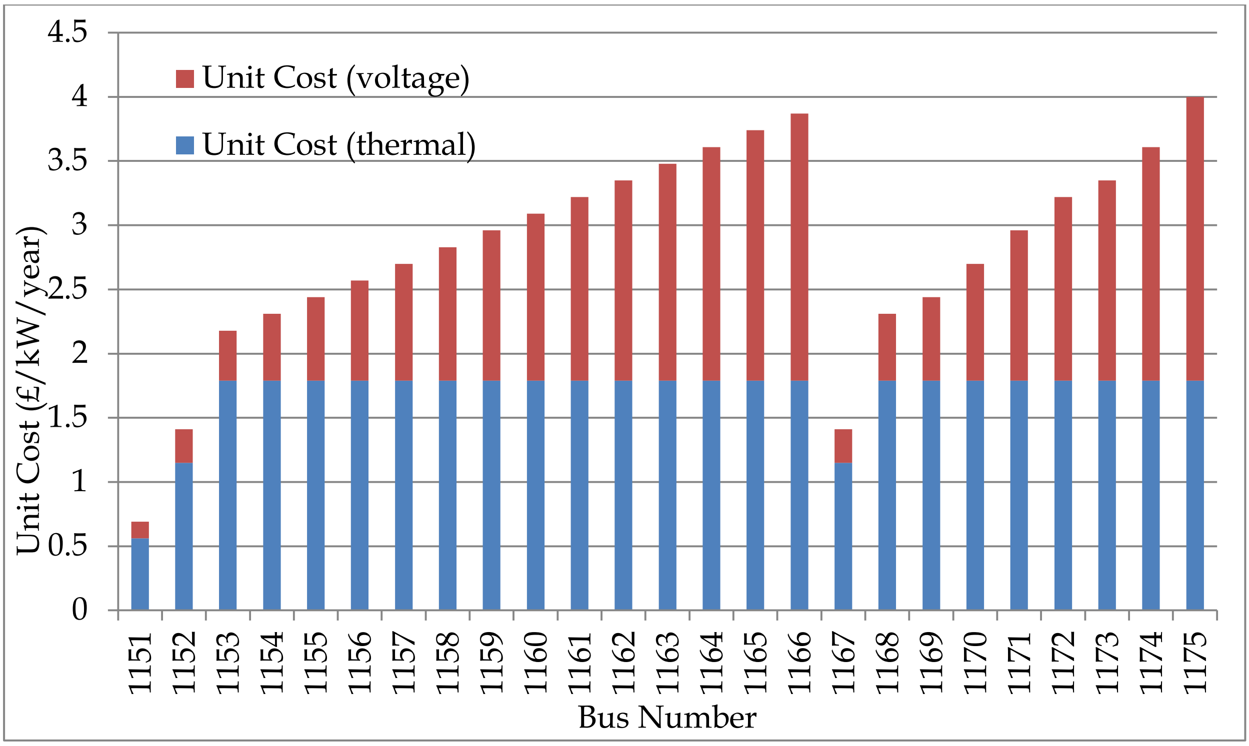


**Figure 5-22 Unit Costs for Loads at the 'Long' Feeder**

## 5.5 Chapter Summary

In this chapter, a new model is proposed to derive cost reflective charges for HV radial distribution networks. The key principle of the model is to allocate long term future reinforcement costs required due to load growth among customers by reference to their contribution to the network upgrading activities. The charging model provides locational charges by recognising the 'extent of use' by customers: the more they use, the higher charges are given.

In this chapter, all feeders are assumed to be able to load to their full capacity as the security driven investment is not considered in the charging model in lower voltage networks. Future work can explore how security constraints can be fed into charging models.

# Chapter 6

# Modelling Large Scale LV Networks

## 6.1 Introduction

In order to assess future reinforcement costs in distribution networks, the method of load flow analysis can be adopted for EHV and HV distribution networks. However, due to extensiveness of network and limited network information for large-scale LV networks, power flow analysis is not practical to be implemented. Therefore, a statistical approach is considered to estimate the condition of LV networks in this thesis and thereafter to investigate reinforcement costs to meet demand growth.

Due to the various characteristics of demographical and network information in different local area, it is proposed that LV networks can be modelled in terms of urban, sub-urban and rural networks with various types and numbers of assets, where the statistical approach can be implemented respectively.

This chapter firstly outlines the approach to categorise LV distribution networks into urban, suburban and rural areas. To do so, load density is calculated by using energy consumption data, population density and population size. Thereafter, the available network data in LV networks is restricted to the overall number of assets, total peak demand and the total capacity of assets of the whole network. Therefore, disaggregating and modelling these assets into the three types of area is necessary.

## 6.2 Approach to Categorise Distribution Networks into Urban/Sub-urban/Rural Considering Load Density

Load density ($MW/km^2$) is defined as the quotient of load and area of the zone geographically accessible to a given distribution network[65]. The load density is used in this study to categorise the whole LV distribution networks into urban, suburban and rural areas. Table 6-1 shows the boundaries of load density in the three types of area[66]. Urban area always has a load density of more than $2MW/km^2$, whereas in rural area, the load density is below $0.5MW/km^2$.

**Table 6-1 Load Density in Urban/Sub-urban/Rural Area**

| Areas | Urban | Sub-Urban | Rural |
|---|---|---|---|
| Load Density ($MW/km^2$) | Above 2 | 0.5~2 | Below 0.5 |

However, load densities in different distribution areas in the UK are not easily available either from DNOs' websites or any public domains. Therefore, this study proposes a method to calculate load density, making use of energy consumption in the UK, population size, and population density. All three data sets are available from public sources [58, 67]. Figure 6-1 shows the flowchart to calculate load density. Detail information of the flowchart is introduced in the following subsections.

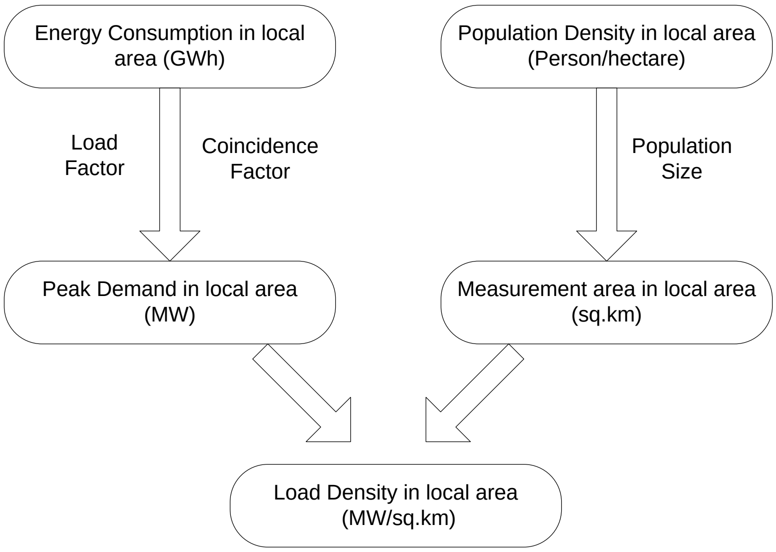


**Figure 6-1 Flowchart of Load Density Calculation**

### 6.2.1 Electricity Consumption at Regional and Local Authority Level

Over the last few years, Department of Energy and Climate Change (DECC) in the UK has developed electricity consumption datasets to regional and local authority levels. The datasets provide electricity sales via the national distribution network for Scotland, Wales and the regions of England for 2008. Domestic sales are distinguished from commercial and industrial sales and the numbers of consumers are given. Table 6-2 shows the information of a selected number of local areas in Central Network East Midlands. The full table is given in Appendix.

**Table 6-2 Electricity Sales in Certain Local Areas of CN East Midlands**

| | | Domestic consumers | Commercial and industrial consumers | All consumers |
|---|---|---|---|---|
| NUTS4 Code | NUTS4 Area | Sales 2008 - GWh | Sales 2008 - GWh | Sales 2008 - GWh |
| UKF1301 | Amber Valley | 224.5 | 383.8 | 608.3 |
| UKF1501 | Ashfield | 195.8 | 409.2 | 604.9 |
| UKF1502 | Bassetlaw | 209.5 | 365.4 | 574.8 |
| UKF2201 | Blaby | 162.6 | 232.2 | 394.8 |
| UKF1201 | Bolsover | 123.2 | 218.2 | 341.4 |

### 6.2.2 Load Factor and Coincidence Factor

Load Factor (LF) is the ratio of the average load over a designated period of time to the peak load occurring in the same period[68].

Coincidence Factor (CF) is used to describe the characteristics of loads that have certain diversity. The diversity means the difference between the sum of the peaks of two or more individual loads and the peak of the combined load[68].

### 6.2.3 Peak Demand in Local Area

With considering load factor and coincidence factors, peak demand for each local area can be calculated using (6-1).

$$Peak \quad Demand_i = \frac{Electricity \quad Consumption \times CF}{8760 \times LF} \tag{6-1}$$

For domestic and non-domestic consumers, different load factors and coincidence factors are always applied. In this study, the values of LF and CF for domestic and non-domestic consumers used are as shown in Table 6-3[69].

**Table 6-3 Load Factors and Coincidence Factors**

| | Load Factor | Coincidence Factor |
|---|---|---|
| Domestic Consumers | 0.8 | 0.4 |
| Non-domestic Consumers | 0.65 | 0.5 |

### 6.2.4 Population Density and Population size

Population density and population size in each individual area are found out through National Statistics website[58]. The population density in each local area is given as number of person per hectare. Then, the measurement area ($km^2$) of each individual local area is computed in $km^2$.

Thereafter, load density is peak demand divided by the area ($km^2$) of each individual area as shown in (6-2):

$$Load \quad Density = \frac{Peak \quad Demand(MW)}{Area(km^2)} \tag{6-2}$$

### 6.2.5 The Proportion of Urban, Sub-urban and Rural areas in UK's Distribution Networks

After obtaining load density for all local areas, by using the boundaries of urban, sub-urban and rural areas illustrated in Table 6-1, the proportion of the three subareas for each distribution networks can be calculated. Equation (6-3) illustrates the approach to calculate the proportion of urban area in LV networks as an example.

$$Urban(\%) = \frac{\sum_{i=1}^{n} PeakDemand_i}{TotalPeak} \tag{6-3}$$

where $n$ is the number of local areas with load densities above 2MW/km², $PeakDemand_i$ is the peak demand in the local area, which can be calculated using (6-1). *TotalPeak* is the overall peak demand in LV networks.

Until now, the proportion of urban, suburban and rural in a large scale LV network can be derived accordingly.

In the UK, there are 14 licensed DNOs each responsible for a distribution services area. Figure 6-2 shows the map of UKs' 14 distribution service areas and Table 6-4 provides the DNOs who are licensed for a specific geographic area shown in Figure 6-2.

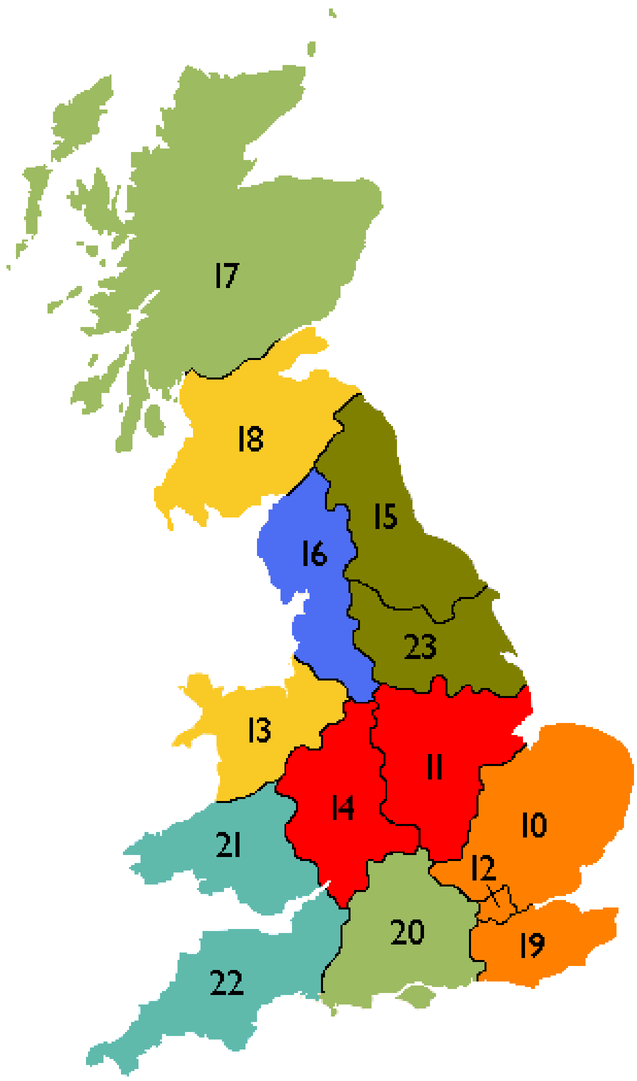


**Figure 6-2 Map of 14 Distribution Service Areas**

**Table 6-4 14 Distribution Service Areas and DNOs**

| Area ID | Area | Company |
|---|---|---|
| 10 | East England | UK Power Networks |
| 11 | East Midlands | Western Power Distribution (Formerly Central Networks ) |
| 12 | London | UK Power Networks |
| 13 | North Wales, Merseyside and Cheshire | Scottish Power Energy Networks |
| 14 | West Midlands | Western Power Distribution (Formerly Central Networks ) |
| 15 | North East England | Northern Power Grid |
| 16 | North West England | Electricity North West |
| 17 | North Scotland | Scottish Hydro Electric Power Distribution |
| 18 | South Scotland | Scottish Power Energy Networks |
| 19 | South East England | UK Power Networks |
| 20 | Southern England | Southern Electric Power Distribution |
| 21 | South Wales | Western Power Distribution |
| 22 | South West England | Western Power Distribution |
| 23 | Yorkshire | Northern Power Grid |

Correspondingly, the calculated proportion of urban, sub-urban and rural areas for 14 distribution areas in the UK is shown in Figure 6-3 and the detailed data is provided in Table 6-5. It can be seen that the London network, owned by UK Power Networks, is all urban area. In contrast, the North Scotland network (SSE Hydro) is mostly rural area, around 67%.

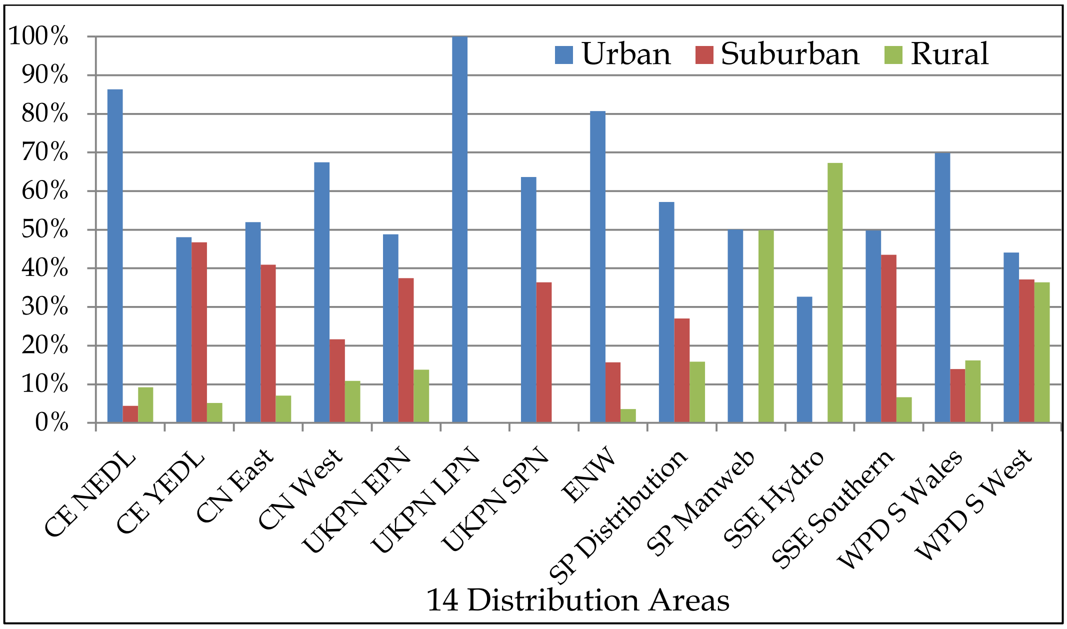


**Figure 6-3 Calculated Load Densities for UK's 14 Distribution Areas**

**Table 6-5 Calculated Load Densities for UK's 14 Distribution Areas**

| | Urban | Subarea | Rural |
|---|---|---|---|
| CE NEDL | 86% | 5% | 9% |
| CE YEDL | 48% | 47% | 5% |
| CN East | 52% | 41% | 7% |
| CN West | 67% | 22% | 11% |
| UKPN EPN | 49% | 37% | 14% |
| UKPN LPN | 100% | 0% | 0% |
| UKPN SPN | 64% | 36% | 0% |
| ENW | 80% | 16% | 4% |
| SP Distribution | 57% | 27% | 16% |
| SP Manweb | 50% | 0% | 50% |
| SSE Hydro | 33% | 0% | 67% |
| SSE Southern | 50% | 43% | 7% |
| WPD S Wales | 70% | 14% | 16% |
| WPD S West | 44% | 37% | 19% |

## 6.3 Approach to Model Network Assets in Urban/Sub-urban/Rural

As mentioned before, the data of LV networks assets is known as total length of underground cables, overhead lines, and the number of transformers and the total capacity of transformers as well as peak demand. The detailed information of LV assets is however not approachable. In this section, the approach of modelling the LV network assets in urban, sub-urban and rural areas is presented. In this approach, disaggregating the system level assets into each area is carried out.

The flowchart in Figure 6-4 illustrates the process of disaggregating the whole LV network assets into urban, sub-urban and rural areas. Further detail explanation about the flowchart is given in the following subsections.

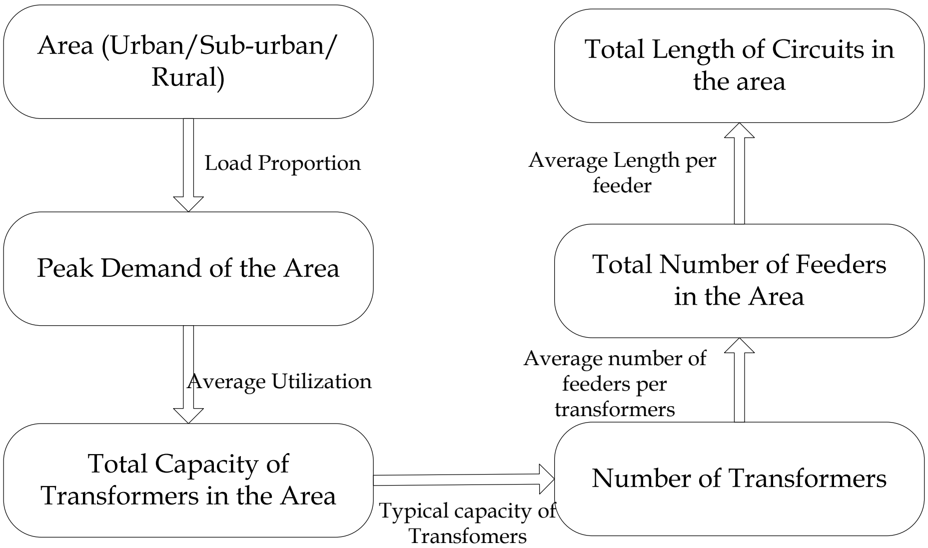


**Figure 6-4 Flowchart of Allocating Assets into Each Area**

### 6.3.1 Peak Demand in Urban/Sub-urban/Rural Areas

As for the only known peak demand in the whole LV network, the method to calculate peak demand in each subarea is presented in (6-4)by taking account of the proportion of subarea and overall peak demand in LV networks. Due to load diversity, coincidence factor should be applied to calculate the peak demand in each subarea to reflect the fact that peak demand in each area does not always peak at the same time.

$$Peak \quad Demand_i = \frac{Peak \quad Demand(MW) \times p_i}{CF} \tag{6-4}$$

where *i* refers to urban, suburban and rural area; *pi* is the proportion of the subarea *i* in the LV network, which is provided in Table 6-5.

### 6.3.2 Average Network Utilisation in Urban/Sub-urban/Rural Area

Average utilisation is the ratio of the peak demand in the subarea to the rated capacity of the system shown in (6-5). It indicates the degree to which the system being loaded during peak load periods with respect to its capacity.

$$Average \quad Utilization_i = \frac{Peak \quad Demand_i}{Capacity_i} \tag{6-5}$$

### 6.3.3 Calculation of Number of Transformers and Circuit Length

The number of transformers can be obtained by the total capacity divided by the typical unit capacity of transformers in each area. Hence, the number of transformers in each subarea can be derived using (6-6):

$$No\_transformers_i = \frac{Peak \quad Demand_i}{Util\_ave_i \times Capacity\_unit} \tag{6-6}$$

where *i* means urban, sub-urban and rural areas; $Util\_ave_i$ is the average utilisation in the target area; *capacity_unit* is the typical capacity of each transformers in the target area.

Similarly, the length of circuits in target area can be calculated by (6-7)

$$L_{total_i} = L_{unit} \times No\_feeders \times No\_transformers_i \tag{6-7}$$

where $L_{unit}$ is the average length of circuits in target area; *No_feeders* is the average number of feeders connected from each transformer in the area; $No\_transformers_i$ is the total number of transformers obtained from (6-6).

Until now, the number of transformers and circuits has been disaggregated into the subareas.

## 6.4 Assumptions

In practical networks, various types of underground cables, overhead lines and transformers as well as other devices are adopted in the network design to achieve the safety and monetary targets. However, it is not practical to take account of all the assets' types and their costs in this study. Therefore, some assumptions are made as follows:

1. Underground cables mostly exist in urban area, whereas majority of overhead lines appears in rural areas. In sub-urban area, there will be a mix of overhead lines and underground cables.

2. The underground cables and overhead lines in the same subarea (urban, sub-urban and rural) have the same parameters, such as capacity, and impedance. The assumption is applicable to transformers as well. In addition, typical transformer capacity in urban area is larger than in the other two areas.

3. The average utilisation of assets in urban areas is higher than those in the other two areas, while rural areas have the lowest utilisation. This assumption is made based on the higher demand density in urban area than the other areas. The similar deduction was also made by[70] in their previous work.

4. Average number of feeders connected from each transformer in each area is assumed, as well as the average length of each feeder. Specifically, since the capacity of a transformer in urban area is generally larger than the one in the other two areas, it is assumed that more feeders are connected with it. In contrast, the circuit length in rural area is longer than the one in urban area due to the lower density of load points.

## 6.5 Demonstration on a Practical Network

### 6.5.1 Network Data

In this section, one of the 14 distribution areas, WPD East Midlands (formerly Central Networks East Midlands), is selected as an example to demonstrate the approach proposed in this chapter. The approachable network data is given in Table 6-6.

**Table 6-6 LV Network Data for Central Network East Midlands[71]**

| Element | Total Number |
|---|---|
| Overhead line(km) | 4971 |
| Underground Cables(km) | 35389 |
| Number of Transformers | 42031 |
| Capacity of Transformers (MVA) | 11709 |
| Peak Demand in LV (MW) | 3740 |

Meanwhile, the proportion of Urban, Sub-urban and Rural of CN East is shown in Table 6-7.

**Table 6-7 the Proportion of Urban, Sub-urban and Rural in CN East**

| | Percentage |
|---|---|
| Urban | 52% |
| Sub-urban | 41% |
| Rural | 7% |

### 6.5.2 Peak Demand in Urban/Sub-urban/Rural Area

Since it is known that the overall peak demand connected in CN East LV networks is 3740 MW. According to CN East's CDCM (Common Distribution Charging Methodology)[69], the same adopted coincidence factor, 0.64, is applied in this study. The peak demand in urban, sub-urban and rural area is calculated by (6-4).

Results are shown in Figure 6-5.

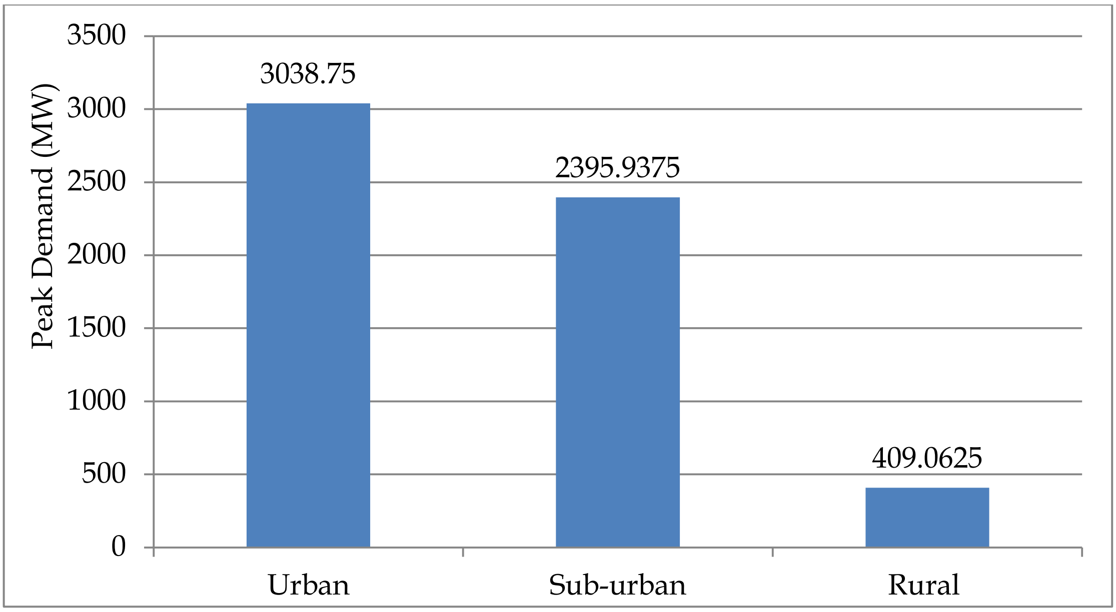


**Figure 6-5 Peak Demand in Urban/Sub-urban/Rural Area**

### 6.5.3 Parameters for Circuits and Transformers

Typical parameters are selected in this study for underground cables, overhead lines and transformers from the Network Design Manual[72] published by E.ON for Central Networks network design. The data for circuits' parameters is shown in Table 6-8.

**Table 6-8 Parameters for Circuits in CN East**

| | Average unit length (km) | UG Capacity (kVA) | OH Capacity (kVA) | Resistance (Ω/km) | Reactance (Ω/km) |
|---|---|---|---|---|---|
| Urban | 0.2 | 102 | - | 0.32 | 0.075 |
| Sub-urban | 0.3 | 55 | - | 0.939 | 0.076 |
| Rural | 0.4 | - | 60 | 0.868 | 0.086 |

It should be noted that although sub-urban area should be the one with the mix of Underground Cables (UG) and overhead lines (OH), in this example, however, overhead lines are all assumed to be in rural area regardless of its existence in sub-urban area. The reason for this assumption is that there are a very small number of overhead lines compared with the total length of underground cables as provided in

Table 6-6. It is noted that the underground cable in sub-urban area is different from the one in urban area with a lower capacity and a different impedance value.

Meanwhile, parameters for transformers are also selected as typical values in terms of capacity, number of feeders connected with each transformer, etc. The data is shown in Table 6-9. It is also assumed that the average number of feeders in each transformer is 5 in urban area, 3.5 in sub-urban area and 1.5 in rural area.

**Table 6-9 Parameters for Transformers in CN East**

| | Unit Capacity (kVA) | No. of feeders connected from Transformers |
|---|---|---|
| Urban | 400 | 5 |
| Sub-urban | 259 | 3.5 |
| Rural | 150 | 1.5 |

### 6.5.4 Average Network Utilisation in Urban/Sub-urban/Rural area

Considering coincidence factor, the average utilisation is derived as 50%. For the difference between urban, sub-urban and rural area, it is assumed as previously mentioned the average utilisation for each area is shown in Table 6-10.

**Table 6-10 Average Utilisation in Urban/Sub-urban/Rural Area**

| | Average Utilisation |
|---|---|
| Urban | 65% |
| Sub-urban | 45% |
| Rural | 35% |

### 6.5.5 Results

Results are shown in Table 6-11 for CN East. Based on the inputs including unit capacity of transformers, number of feeders connected into transformers as well as the unit length of feeders in each subarea, the outputs such as the number of transformers, length of circuits and total capacity of transformers in each subarea are computed using the approach introduced in Section 6.3 in this study. Meanwhile, the resulting total number of assets and their capacity in the whole LV network is illustrated in Table 6-11, which is comparable with the data information provided by DNOs shown in Table 6-6.

**Table 6-11 Computed Results based on Assumptions**

| | Inputs | | | | | Outputs | | |
|---|---|---|---|---|---|---|---|---|
| | Ratio | Unit Capacity (KVA) | No. of Feeders connected in Transformers | Unit Length | Util_ave | Number | | Total Transformer Capacity (MVA) |
| | | | | | | Transformers | Circuits (km) | |
| Urban | 52% | 400 | 5 | 0.2 | 0.65 | 12273 | 12273 | 4909 |
| Sub-urban | 41% | 259 | 3.5 | 0.3 | 0.45 | 21562 | 22640 | 5585 |
| Rural | 7% | 150 | 1.5 | 0.4 | 0.35 | 8196 | 4918 | 1229 |
| Total in the Whole LV network | - | - | - | - | - | 42031 | 39831 | 11723 |

## 6.6 Chapter Summary

This chapter presents the approach to model LV distribution networks in terms of urban, sub-urban and rural areas. Under the condition that limited pubic data information is known, we firstly propose the approach to categorise distribution networks into the three types of areas considering load density. Thereafter, the aggregated network assets are then allocated into the three areas. The work conducted in this chapter is the basis of work to evaluate LV network reinforcement costs due to demand growth as well as LV distribution networks charges in the following chapters.

# Chapter 7

# Quantification of Large-Scale LV Network Reinforcement Costs with a Statistical Method

## 7.1 Introduction

The GB electricity network is expected to see some fundamental changes in the coming years, particularly in the longer term up until the 2030 and 2050 timeframes. To a large extent, this change is driven by environmental objectives set out at both European Union (EU) and national levels. In support of the 2050 CO2 reduction target by the UK government [3], significant electrification of the heat and transport sectors is expected, particularly from the late 2020s onwards. Such developments will present challenges for both the operation and planning of the future infrastructure networks both at the transmission and distribution levels.

It is expected that the potential huge demand growth, due to the connection of heat pumps and electrical vehicles, appears at lower voltage distribution networks. A typical distribution system is therefore constantly growing in order to accommodate the growth in demand of both existing customers and new customers. Distribution network investment planning aims to meet these demand growth at the least network reinforcement and expansion costs as they are both expensive and long-lasting. Making the correct investment decisions during the planning process is therefore essential [73] to DNOs, otherwise, the consequence would be the failure to facilitate the new demand increase or the costly overinvestment. Moreover, the projected long-term investment costs will be fed into charging methodologies to recover the costs from the distribution network users [6, 29, 74]. Overall, the appropriate assessing the long-term distribution network investment not only impacts DNOs' business but also the end users who need to pay for the investment costs in terms of use-of-system charges. Therefore, the appropriate approach to evaluate future reinforcement costs plays an essential role.

For EHV distribution networks, the evaluation of wide-area reinforcement costs is performed using professional simulation approaches, such as power flow tools, which identify network pinch points and necessary upgrades or expansion[29]. These simulation approaches require a wide range of detailed network information ranging from parameters for every single network asset to time-tagged loading levels at each branch under normal and contingency conditions.

Although DNOs have aggregated network asset information for LV distribution networks, they have limited access to the specific assets' loading conditions. Moreover, network configuration in LV networks is extensive and therefore power flow tools are deemed too complex to be practical for the purpose of long term network investment planning at the system level. Currently in the UK, in need of future reinforcement costs for LV networks, historic data for past years is simply scaled to be the future costs[6]. Such linear extrapolation can hardly estimate the current system conditions or the future development trend.

There are a number of mathematical and computational methods adopted for LV distribution network investment planning with the aim of achieving optimal design of network configuration and location of transformers under minimum costs, including dynamic programming [75], heuristic algorithm [76], genetic algorithm [77] mixed integer nonlinear programming problem solved by Tabu Search[78] and evolution strategies [79, 80]. However, the scopes of these methods are restricted to considering the optimal network investment planning for a small problematic network where perfect network information is available. It is safe to say that all existing LV network design packages aim to assist immediate network design due to the connection of a new user or the violation of supply security. This represents a reactive approach. There needs a proactive LV planning tool at the system level that can make the most use of the limited network information to model LV distribution networks and evaluate long-term future investments requirement.

In the UK, generic network models are developed in [64, 81] to represent large-scale distribution networks. However, only EHV and HV (HV-11kV and 6.6kV in the UK) network models are developed, not for LV networks. Such models for LV distribution networks in Germany are discussed in [82, 83]. Models are typically specified separately for suburban and rural areas in terms of capacity of transformers, number of feeders and length of circuits, representing different load densities. These LV models can effectively serve as testing and demonstration platforms for network analysis, for example assessing the impact on LV networks with the presence of PV [83]. However, in terms of quantifying investment costs at the system level, such models are not suitable as they do not represent LV networks characteristics thoroughly.

In this chapter, a novel statistical approach is proposed to evaluate the future demand-driven reinforcement costs of a practical LV distribution network over a given time period. Instead of detailed power flow analysis for subsets of a network, it proposes the use of a probability distribution to represent the condition of the huge volume of assets in a large scale LV network. Here, the triangular distribution is used, which can be defined by three parameters: the mode, minimum and maximum of assets' utilisation. This approach can be extended to investigate reinforcement activities driven by either breaching assets' thermal limits or bus-bar voltage limits as a result of demand growth. This approach acknowledges the inherent uncertainties associated with network assets usage due to the limited amount of information that is available.

# 7.2 Triangular Distribution Function

## 7.2.1 Definition

The triangular distribution can be used to represent the distribution of variables where the level of information required to accurately specify more complex alternatives is not available, especially in cases where the relationship between variables is known but data is scarce (possibly because of the high cost of collection). It is derived based on the knowledge of the minimum and maximum and expert elicitation or an 'informed guess' of the value of the mode value [84].

### 7.2.1.1. **Probability Density Function[85]**

The triangular distribution is a continuous probability distribution defined with lower limit $\alpha$, mode $\gamma$ and upper limit $\beta$. Its Probability Density Function (PDF) is described in (7-1) and graphically depicted in Figure 7-1.

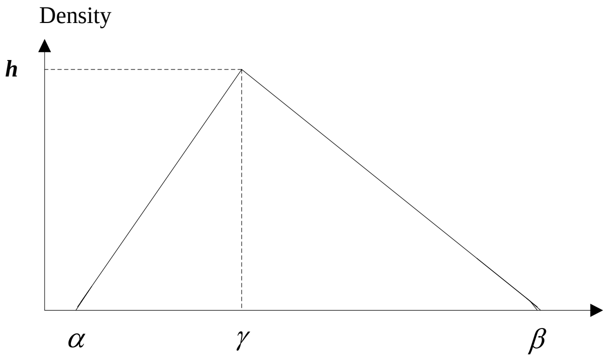


**Figure 7-1 Probability Density Function of Triangular Distribution**

$$f(x) = \begin{cases} 0 & x \le \alpha \\ \dfrac{2(x-\alpha)}{(\beta-\alpha)(\gamma-\alpha)} & \alpha \le x \le \gamma \\ \dfrac{2(\beta-x)}{(\beta-\alpha)(\beta-\gamma)} & \gamma \le x \le \beta \\ 0 & x \ge \beta \end{cases} \tag{7-1}$$

where, $x$ is random variable with minimum α, maximum β and mode γ.

The density at the mode γ is derived in terms of the minimum and maximum:

$$h = \frac{2}{\beta - \alpha} \tag{7-2}$$

#### 7.2.1.2. Expectation

In probability theory, the expectation of a random variable is a weighted average of the possible values that the random variable x can take on, each weighted by the probability of occurrence [86]. For a continuous probability distribution, the expectation of x with a probability density function f(x) is defined as follows:

$$E(x) = \int_{-\infty}^{\infty} x \cdot f(x) \cdot dx \tag{7-3}$$

Therefore, the expectation of f(x) given in (7-1) is:

$$E(x) = \int_{\alpha}^{\gamma} x \cdot f(x) \cdot dx + \int_{\gamma}^{\beta} x \cdot f(x) \cdot dx \tag{7-4}$$

The expectation of x will therefore depend on the three key parameters that define a triangular distribution as shown in (7-5):

$$E(x) = \lambda = \frac{\alpha + \beta + \gamma}{3} \tag{7-5}$$

### 7.2.2 Rationale of Using Triangular Distribution

The accuracy of network planning calculations depends largely on the quality of the available data. However, the huge data requirement over the extensive LV network makes it difficult to investigate the reinforcement activities and quantify future reinforcement costs. For this reason, statistical methods are utilised to represent LV networks' condition in terms of system utilisation and assets information. The identification of the most appropriate probabilistic distribution functions to represent the LV network condition involves an extensive analysis of the literatures [87-89]. The beta distribution has been suggested as the most suitable for describing the distribution of electrical load based on analysis of real data collected from data acquisition systems[88]. In such cases, the parameters of the beta distribution were estimated from the available data[87]. However, its practical use in this setting is limited due to the absence of the information required in order to accurately estimate the parameters. Moreover, the estimation of the parameters and general understanding of the properties of the beta distribution are not commonly understood [90].

The triangular distribution provides an approximation to the beta distribution [90, 91]. Details of the triangular distribution can be seen in the Appendix. Its relative simplicity means that it can be constructed based on less information in comparison to other probability distributions, such as the beta, log-normal or gamma. Properties of the triangular distribution that make it a suitable choice for this application include the following:

1. It can easily represent the skewness in both directions, i.e. right-hand or left-hand, either of which might occur under different network conditions.

2. It allows a full probability distribution to be defined based on three parameters, the mode, minimum and maximum. These parameters can be derived from both practical data and expert elicitations in an easier fashion than with more complex distributions.

3. It can be incorporated into voltage drop investigation, which is one of the critical issues resulting in LV network reinforcement activities. Further details are given in Section III.

The simplicity of the form of the distribution means that it provides an understandable solution that can be readily implemented in practice by DNOs. The triangular distribution can represent the distribution of variables where the level of information required to accurately specify more complex alternatives is not available (possibly because of the high cost of collection). It is derived based on the knowledge of the minimum and maximum and expert elicitation or an 'informed guess' of the value of the mode value [84].

## 7.3 Development of a Statistical Reinforcement Costs Calculation Approach

In this section, the application of the triangular distribution to LV network reinforcement cost evaluations is presented. In this chapter, the LV reinforcement is considered to be driven by demand increase only.

### 7.3.1 Reinforcement Schemes

In LV distribution networks planning, future reinforcement costs are largely driven by thermal or voltage violations due to either demand growth or generation growth. The scope of this study is restricted to investigating reinforcement activities due to demand growth since current LV distribution networks are demand dominated. Therefore, the presence of DGs/MGs and their contribution into reinforcement costs are out of the scope of this chapter. In this study, two types of network reinforcement schemes are considered:

1. Reinforcement of a circuits or transformer if its thermal capacity limit is violated;
2. Inserting a new transformer to split the circuit if voltage limit is violated[59].

Accordingly, two methods are introduced to examine reinforcement activities driven by thermal violation and voltage violation separately.

### 7.3.2 Application of Triangular Distribution: Thermal Driven Investigation

The triangular distribution is used to describe the distribution of assets utilisation of the whole or a subset of LV network as shown in Figure 7-2 (a) so as to identify thermal driven reinforcement.

Here, the lower limit α and the upper limit β represent the lowest and highest utilisation of circuits or transformers in the study network, both of which can be judged by experienced distribution network operators. From (7-5), γ can be derived by submitting to (7-6):

$$\gamma = 3 \cdot \lambda - \alpha - \beta \tag{7-6}$$

where λ is the expectation as defined in (7-5).Once γ is identified, the triangular distribution is formed.

Often a network operator has the knowledge of the transformer capacity of the entire network, the peak demand and Coincidence Factor (CF). The CF is defined as the ratio of the peak demand to the sum of individual peak demand of each load [68]. The factor is designed to recognise the fact that all loads do not normally peak at the same time and therefore the sum of the individual peak loads is greater than the peak demand [68]. Peak demand D over CF represents the sum of individual peak demand across the LV network. Therefore, D/CF divided by installed capacity C is the average utilisation of system transformers:

$$\lambda = Util_{ave} = \frac{D/CF}{C} \tag{7-7}$$

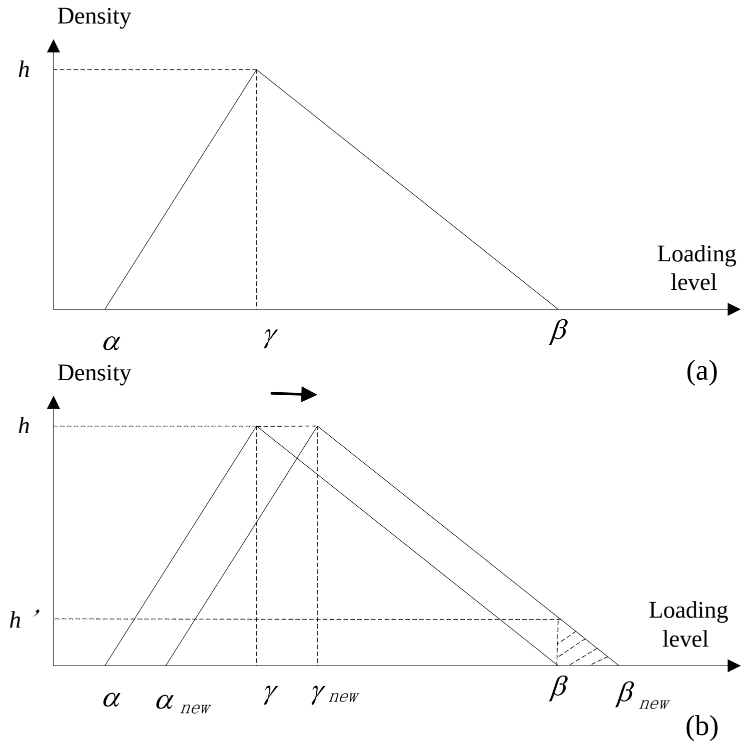


**Figure 7-2 Triangular Distributions for Thermal Driven Investigation**

Given a uniform projected load growth rate across the whole LV network, demand will increase from $D$ to $D_{new}$ over a specified period. The utilisation of all existing network assets will therefore rise uniformly at the load growth rate. Such increase causes the triangular distribution to shift at the same rate. In this case, the new expected average utilisation λ can be derived by (7-8):

$$\lambda_{new} = \frac{D_{new}/CF}{C} \tag{7-8}$$

This shift creates a shaded area with the proportion of the network assets exceeds the maximum utilisation β, as shown in Figure 7-2. This area indicates the proportion of network assets that are required to reinforce because of demand increase. The consequential network reinforcement cost can therefore be determined by (7-9):

$$Cost_{thermal} = P_{thermal} \cdot N_{assets} \cdot Cost_{unit} \tag{7-9}$$

where, $P_{thermal}$ is the proportion of the network assets represented by the shadow area in Figure 7-2(b), $N_{assets}$ is the total number of assets in the system(circuits/transformers), and $Cost_{unit}$ is the unit cost of typical network assets.

### 7.3.3 The Application of Triangular Distribution: Voltage Driven Reinforcement Activity

Network reinforcement activities are not only driven by thermal ratings of assets but also by busbar voltage limits to ensure security and quality of supply. In the UK, the Electricity Safety, Quality and Continuity (ESQC) [63] states that the voltage levels in the LV networks should be maintained within +10% and -6% of deviation from the nominal 230V. The scope of this study is to investigate demand driven reinforcement in the LV network, where voltage violations come before thermal violations. As this study is focused on demand driven network reinforcement, hence, the maximum allowed voltage drop is 6% from the nominal to comply with the UK standards. This section presents the approach to apply the triangular distribution to determine the LV network reinforcement driven by voltage violation.

It should be noted that ΔVmax is 6% only when the voltage from the HV/LV transformer is nominal 230V. Otherwise, the ΔVmax needs to be calculated to make sure keeping the voltage within the statutory limits at customers' side [92].In distribution systems, the last network asset to control voltage in LV networks is transformers at primary substation, stepping down from 33KV to 11kV (EHV/HV). The voltages at all 11kV busbars are controlled within +/-6% by the primary substation in the UK. Therefore, for LV (11/0.4kV) transformers, the source voltage from these transformers (11/0.4kV) depends on the voltage of the 11kV busbars where they connected. Under this circumstance, maximum allowed voltage drops on the vast number of LV circuits would be different from each other. For example, if the source voltage from LV transformers is 106%, then 12% maximum voltage drop is allowed on the circuit, whereas, if it is 94%, maximum voltage drop allowed is 0. With this upper and lower allowance, 6% can be considered as the average allowed maximum voltage drop with the average source voltage being nominal.

Meanwhile, it would be extremely complex and hardly achievable to specify the maximum allowed voltage drop for each circuit in the entire LV networks because: i) there are no such detailed data of the source voltage for LV transformers; ii) it cannot pinpoint the number of the circuits connected from a LV transformer with a specific source voltage and their length. Since we target an overall reinforcement costs for the entire LV networks, in this study we used 6% as allowed maximum voltage drops along all the circuits, which is reasonable and acceptable.

#### 7.3.3.1. **Voltage Drop Calculation**

The p.u. voltage drop at a busbar can be approximated by (7-10)[93]:

$$\begin{aligned} \Delta V &\approx PR + QX = S\cos\varphi R_0 l + S\sin\varphi X_0 l \\ &= (\cos\varphi R_0 + \sin\varphi X_0) Sl \end{aligned} \tag{7-10}$$

where, $R_0$ and $X_0$ are the p.u. resistance and p.u. reactance of 1km circuit, $l$ is the circuit length, $S$ is the power flow carried by the circuit and φ is power factor.

#### 7.3.3.2. **Threshold for Voltage Driven Reinforcement**

As observed from (7-10), the voltage drop along a circuit can be determined by both the circuit's loading level and its length if we assume a uniform power factor and circuit types with constant parameters of circuits. If the maximum allowed voltage drop is 6% from the nominal, then it is possible to find the condition when voltage-driven reinforcement is required. Rearranging (7-10), the threshold condition for a voltage driven reinforcement is given as $(S^*l)_{thresh}$ in (7-11). Voltage violation happens on the circuit if the product of the loading level $S$ and the circuit length $l$ fulfils the following statement:

$$S * l \geq (S * l)_{thresh} = \Delta V_{\max} / (\cos\varphi * R_0 + \sin\varphi * X_0) \tag{7-11}$$

where $\Delta V_{max}$ is the maximum allowed busbar voltage drop. In this chapter, power factor is assumed as 0.95 through the whole study, which is the commonly used by the UK's DNOs in setting network charges[69].

#### 7.3.3.3. **Triangular Distribution for Voltage Driven Investigation**

Since voltage driven reinforcement is determined by two variables, two triangular distributions are used to represent the diverse circuits loading level $S$ and circuit length $l$, as shown in Figure 7-3 (a) and (b).

In LV networks, there are hundreds of thousands of circuits, which come with quite diverse length. Triangular distribution is used to represent the distribution of this huge volume of circuit length as shown in Figure 7-3 (b). The lower limit $\alpha_2$ and the upper limit $\beta_2$ represent the shortest and the longest circuit length in a LV network. Again, the triangular distribution can be completely specified when $\gamma_2$, is identified using (7-6). Here, λ2 is the average length of circuits in LV networks.

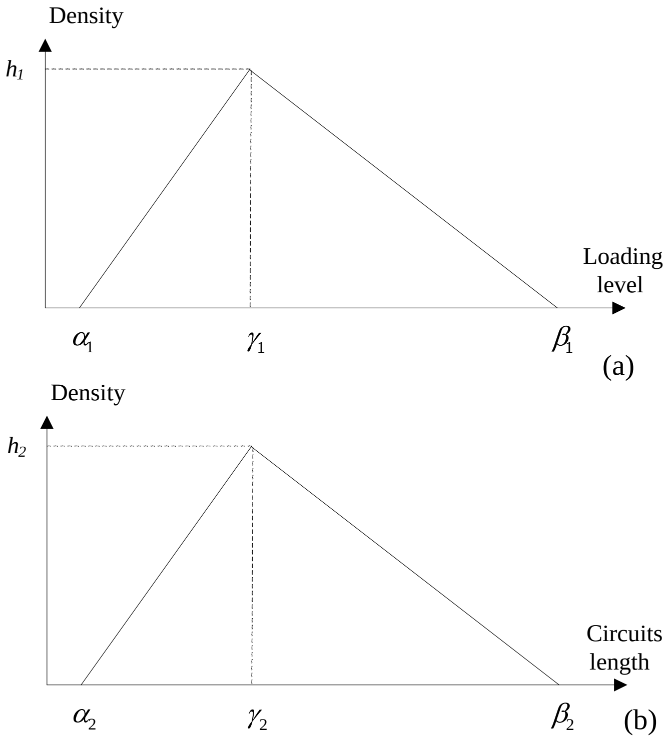


**Figure 7-3 Triangular Distribution for Voltage Driven Investigation**

#### 7.3.3.4. **Discretisation for Voltage Driven Investigation**

In order to estimate the distribution of the product of $S$ and $l$, a simple discretisation is used that discretises the continuous distribution without the significant loss of precision. A higher level of precision may be achieved by either Monte-Carlo simulation or a closed-form expression of the exact probability density function if it is available [85]. However, any increases in precision will come at the cost of significantly higher computational burden.

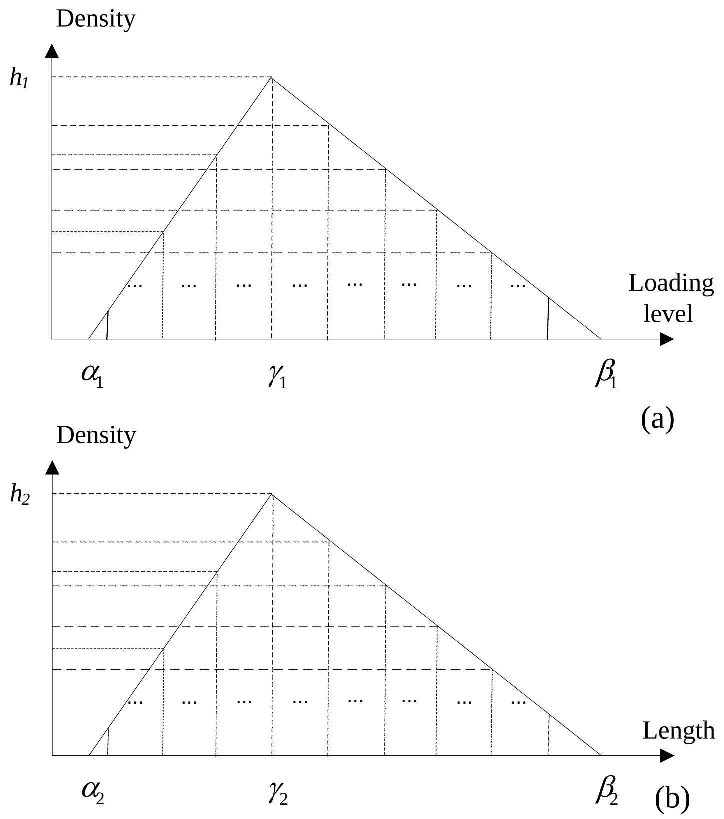


**Figure 7-4 Discretisation of Triangular Distribution for Voltage Driven Investigation**

Equal-width discretisation is employed here, which divides the range of the attribute into a fixed number of intervals with equal length. The interval length between two discrete points for the two distributions are derived with

$$\Delta_1 = (\beta_1 - \alpha_1) / m \tag{7-12}$$

$$\Delta_2 = (\beta_2 - \alpha_2) / n \tag{7-13}$$

where, $m$ and $n$ are the number of discrete points for each distribution.

**Table 7-1 Discretisation of Triangular distributions**

| Loading Level Distribution | | Circuits' Length Distribution | |
|---|---|---|---|
| Discrete Point | Probability | Discrete Point | Probability |
| $\alpha_1 + \Delta_1$ | $p_{t1}$ | $\alpha_2 + \Delta_2$ | $p_{l1}$ |
| $\alpha_1 + 2\Delta_1$ | $p_{t2}$ | $\alpha_2 + 2\Delta_2$ | $p_{l2}$ |
| $\cdots$ | $\cdots$ | $\cdots$ | $\cdots$ |
| $\alpha_1 + (m-1)\Delta_1$ | $p_{t(m-1)}$ | $\alpha_2 + (n-1)\Delta_2$ | $p_{l(n-1)}$ |

Figure 7-4 illustrates how the equal-width discretisation is implemented for both utilisation and length distributions. Table 7-1 provides the detailed information of the distributions after equal-width discretisation be employed.

The probabilities for both of the discrete distributions can therefore be calculated respectively by:

$$P(s_i) = \frac{h(s_i)}{\sum h(s_i)} \tag{7-14}$$

$$P(l_i) = \frac{h(l_i)}{\sum h(l_i)} \tag{7-15}$$

where, $h(s_i)$and $h(l_i)$ are the probability densities of loading level $S_i$ and circuits length $l_i$ as obtained in triangular distribution.

#### 7.3.3.5. Voltage Driven Reinforcement Costs Calculation

Let $T_0$ be the threshold value of voltage violation, which can be derived in (7-16) as follows:

$$T_0 = \frac{0.06}{(\cos\varphi R_0 + \sin\varphi X_0)} \tag{7-16}$$

where $R_0$ and $X_0$ are the circuit parameters per unit and $\varphi$ is power factor angle. In this study, power factor is assumed as 0.95 through the whole study, which is the commonly used by the UK's DNOs in setting network charges[69].

Furthermore, $T_{ij}$, which is calculated using (7-17), represents the circuits with certain loading levels and length

$$T_{ij} = S_i * L_j \tag{7-17}$$

If $T_{ij} \geq T_0$, the circuits are regarded as voltage violation and meanwhile, the proportion of these circuits in the network can be derived accordingly using (7-18).

$$P_{voltage} = P(T_{ij} \geq T_0) = \sum (P(s_i) * P(l_j))\Big|_{T_{ij} \geq T_0} \tag{7-18}$$

Therefore, the reinforcement costs due to voltage violation can be obtained using (7-19)

$$Cost_{voltage} = P_{voltage} * Amount_{circuits} * TransCost_{unit} \tag{7-19}$$

where $P_{voltage}$ is the proportion represented by the calculation using (7-18); $Amount_{circuits}$ is the total number of circuits in the target network and $TransCost_{unit}$ is the unit cost of transformers. It should be noted again that the new transformers are inserted into the circuits with voltage violation problem to split the circuits to bring back the voltage as stated in the reinforcement schemes.

### 7.3.4 Reinforcement Drivers Investigation

It is possible to investigate the main drivers for reinforcement activities in the target network. Assuming circuits with the rating $S_0$ and allowed voltage drop limit 6%, the threshold length $L_0$ can be calculated using (20):

$$L_0 = \frac{0.06}{(\cos\varphi R_0 + \sin\varphi X_0) * S_0} \tag{20}$$

where $S_0$ is the circuit rating , $R_0$ and $X_0$ are the circuit parameters per unit and $\varphi$ is determined by the power factor.

Then, it can be concluded that reinforcement activities for circuits with length less than $L_0$ are driven by thermal violation. In contrast, reinforcement activities for circuits with length more than $L_0$ are driven by voltage violation. In this case, for the target network area, it is possible to recognise the main drivers for reinforcement costs firstly, and after this, reinforcement costs can further be investigated.

# 7.4 Demonstration on a Practical Network

In this section, the method proposed in this chapter is demonstrated on a practical LV network from the UK, which is owned by one of the DNOs, Central Networks. The total peak demand connected at CN East LV network is 3740MW with a power factor 0.95. The Low Voltage network is designed as radial feeders from 11kV/LV distribution substations. The total capacity of transformers is 11709MVA.

As mentioned in the previous chapter, the LV network is categorised into urban, suburban and rural areas due to various characteristics of demographical and network information. In this chapter, the proposed statistical method is carried out in the three areas respectively, which means that Triangular Distributions with different parameters are formed to represent the main characteristics of each area.

## 7.4.1 Network Representation Using Triangular Distribution

### 7.4.1.1. **Assets Utilisation/Loading Level in Urban, Suburban and Rural Areas**

To form Triangular Distribution, three parameters are needed as the lower limit α, the upper limit β and the mode γ as shown in Figure 7-1. For thermal driven investigation, the lower limit α and upper limit β of the Triangular Distribution represents the assets' lowest and highest utilisation. The highest utilisation β can also be regarded as the maximum allowed utilisation, which means once the utilisation of assets exceed β reinforcement activities are needed. The mode γ is determined by (7-3) once the rest of three parameters, α, β and Expectation Value, which can also be regarded as mean, λ are all known.

In the case study of the previous Chapter, the average utilisation of urban, suburban and rural areas in LV networks, Central Networks East is calculated as shown in Table 7-2. The lower limit α and upper limit β for each area comes from empirical data as shown in Table 7-3. It is assumed here that the maximum allowed utilisation for all the assets are 95%.

**Table 7-2 Average Utilisation in Urban/Sub-urban/Rural Area in CN East**

| | Average Utilisation |
|---|---|
| Urban | 65% |
| Sub-urban | 45% |
| Rural | 35% |

**Table 7-3 Parameters for Triangular Distribution: Thermal Driven Investigation**

| | | Transformers | Circuits |
|---|---|---|---|
| Urban | α | 0.15 | 0.15 |
| | β | 0.95 | 0.95 |
| | γ | 0.85 | 0.65 |
| Suburban | α | 0.05 | 0.05 |
| | β | 0.95 | 0.95 |
| | γ | 0.35 | 0.45 |
| Rural | α | 0.03 | 0.03 |
| | β | 0.95 | 0.9 |
| | γ | 0.07 | 0.35 |

Figure 7-5, 7-6 and 7-7 show the three triangular distributions for urban, suburban and rural areas respectively, aiming at investigating thermal driven reinforcement activities. It can be observed that in the urban area, most of assets are much more highly utilised than that of the other two, reaching around 80% utilisation. In contrast, the assets' utilisations in the rural areas mostly appear at less than 20%. It indicates that the spare capacity of the network to meet future load growth in the urban area is collectively less than the one in suburban and rural area. Potential more reinforcement activities might be needed in urban area to meet future demand growth.

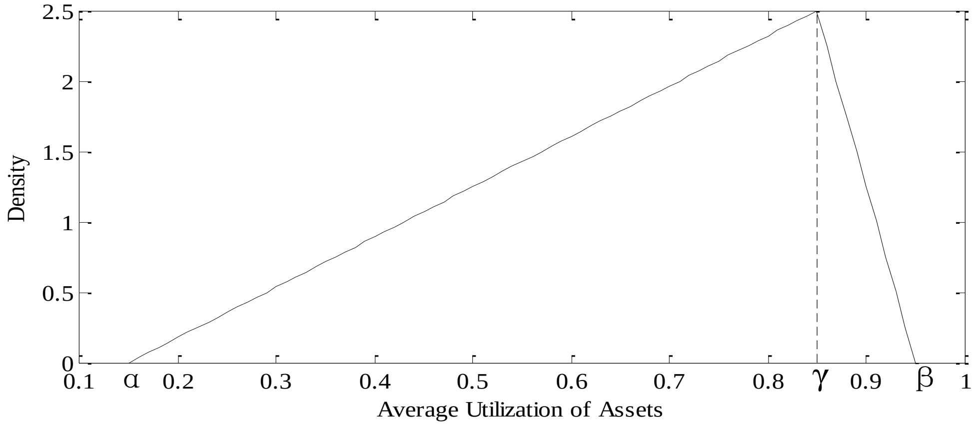


**Figure 7-5 Triangular Distribution of Assets Utilisation for Urban Area**

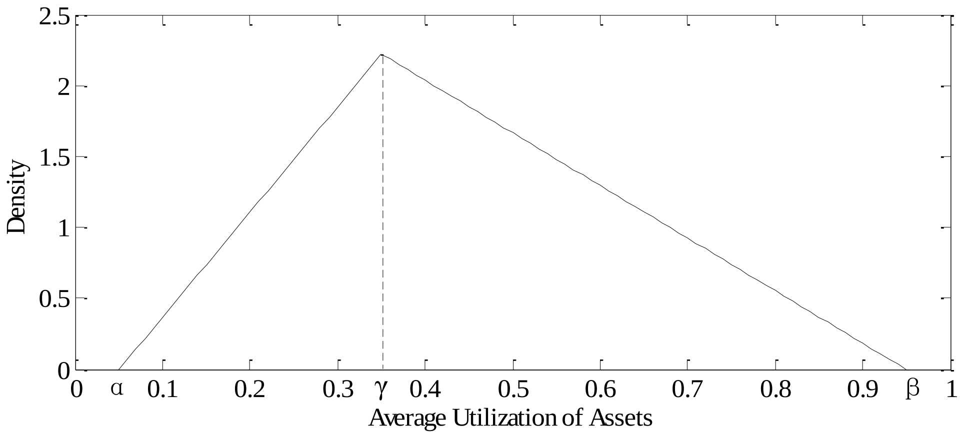


**Figure 7-6 Triangular Distribution of Assets Utilisation for Suburban Area**

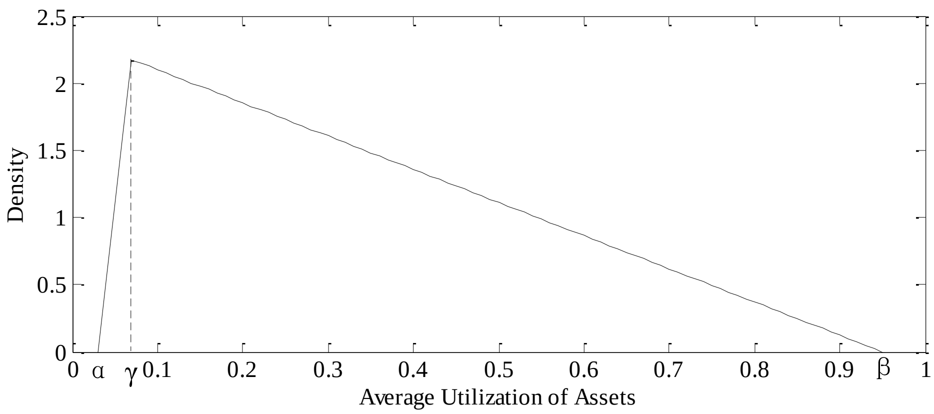


**Figure 7-7 Triangular Distribution of Assets Utilisation for Rural Area**

#### 7.4.1.2. Circuits Length Distribution

Average lengths of circuits in urban, suburban and rural areas are assumed as 200m, 300m and 400m, respectively according to distribution network design. Besides, the parameters, α and β, which represent the smallest and largest length of circuits in the network, are respectively assumed as shown in Table 7-4.

**Table 7-4 Parameters for Triangular Distribution: Circuits Lengths**

| | Urban | Suburban | Rural |
|---|---|---|---|
| α (m) | 50 | 65 | 80 |
| β (m) | 500 | 650 | 800 |
| γ (m) | 200 | 300 | 400 |

### 7.4.2 Calculation of Reinforcement Costs

Demand growth rate is taken as 2.1% each year[1], which comes from the prediction by UK's DNOs [94]. Typical assets' unit costs are selected for this study for simplicity purpose although in practice, various types of assets are used. The assets costs used in this study are shown in Table 7-5. Apparently, the unit costs both transformers and circuits are much more expensive in urban areas than in suburban and rural areas, as the cost of underground cables is much higher than overhead lines. Moreover, the assets with larger capacity have potential higher costs.

[1] 2.1% is the load growth rate predicted by the DNO; otherwise, when load growth rate is uncertain the uniform 1.6% is used throughout, which is the project long-term load growth rate in the UK.

**Table 7-5 Circuits and Transformers Unit Costs**

| | Circuits Costs (£/km) | Transformer costs (unit) |
|---|---|---|
| Urban | 67200 | 26400 |
| Suburban | 16400 | 16100 |
| Rural | 16400 | 5800 |

Reinforcement costs due to demand growth for 5 years are calculated for the Central Networks East Midlands in the first place. The reinforcement activities driven by thermal and voltage violation are therefore investigated.

#### 7.4.2.1. **Reinforcement Cost Driven by Thermal Violation**

With a load growth rate, 2.1% each year, the total number of assets needed to be reinforced due to thermal violation is worked out for a five-year period. Table 7-6 shows the total length of circuits and number of transformers for urban, suburban and rural area.

**Table 7-6 Amount of Assets Reinforcement Needed due to Thermal Violation**

| | Circuits (km) | Transformers |
|---|---|---|
| Urban | 841 | 805 |
| Suburban | 70 | 98 |
| Rural | 7 | 15 |

#### 7.4.2.2. **Reinforcement Cost Driven by Voltage Violation**

Table 7-7 illustrates the number of transformers needed if there is voltage violation because of load growth in the five-year period in the urban, suburban and rural area of Central Network East. The results indicate that seldom voltage violation happens in the urban area.

**Table 7-7 Amount of Transformers Needed due to Voltage Violation**

| | Inserted Transformers |
|---|---|
| Urban | 0 |
| Suburban | 1174 |
| Rural | 453 |

#### 7.4.2.3. Reinforcement Drivers Investigation

The final reinforcement costs for Central Network East in five-year period are shown in Table 7-8.

**Table 7-8 General Reinforcement Costs for LV Networks in CN East**

| | Circuits Costs (£1000) | Transformers Costs (£1000) | Total (£1000) |
|---|---|---|---|
| Urban | 82,802 | 21,259 | 104,061 |
| Suburban | 3,456 | 20,492 | 23,948 |
| Rural | 112 | 2,717 | 2,830 |
| Overall | 86,370 | 44,468 | 130,839 |

The overall general reinforcement cost is around £131million over the study period, from 2010 to 2015. Meanwhile, as described in[95], the estimated general reinforcement by network company for LV network in 2007/2008 period is £26million. Therefore, the proposed method in this chapter can be validated to derive a reasonable reinforcement cost for LV networks. Besides that, this method can also investigate the main drivers resulting in reinforcement activities as shown in Figure 7-8. In the example network, over the study period, the reinforcement cost happening in urban area are mostly caused by thermal violation whereas in rural area, a large proportion of reinforcement costs is driven by exceeding voltage limits. The results can make DNOs to understand their owned network more vividly and further guide the network planning in a more reasonable way.

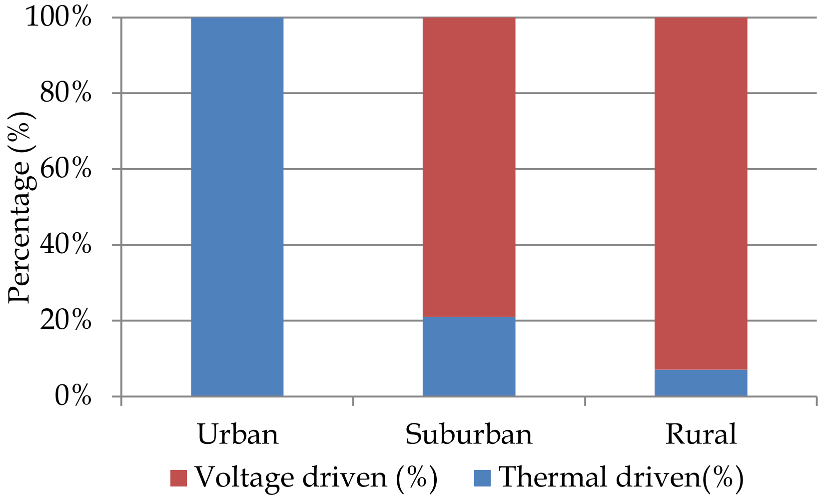

**Figure 7-8 Drivers for Reinforcement Activities**

### 7.4.3 Reinforcement Costs under Different Load Growth Rates

In this section, different load growth rates are assigned for the LV network in Central Network East. Reinforcement costs are respectively carried out for the LV network as shown in Figure 7-9. It is expected that with higher load growth rate for the network, there are larger reinforcement costs required to meet the demand growth. In addition, it can be observed that reinforcement activities most exist in urban areas especially when load growth is high. One of the reasons is that unit assets costs in urban area are more expensive than the one in suburban and urban area. In addition, current higher utilisation of network in urban area than suburban and rural areas makes more requirements on reinforcement activities due to demand growth.

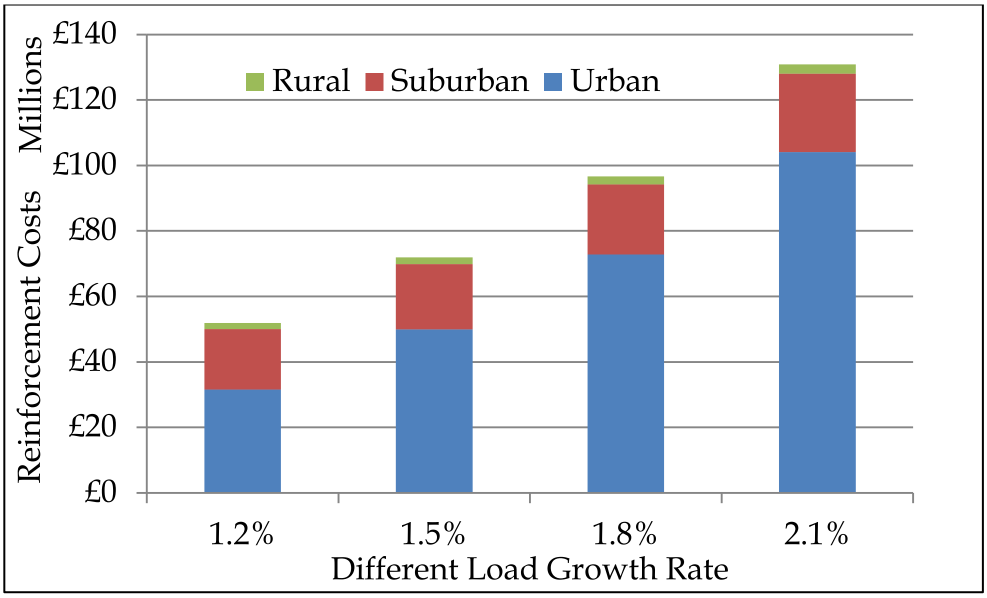


**Figure 7-9 Reinforcement Costs under Different Load Growth Rate**

The results indicate that the predication of load growth is important as the reinforcement horizon of network assets is directly affected by the degree of load increase.

### 7.4.4 Sensitivity Study on Parameters of Triangular Distribution

In this study, the determination of the lower limit α and upper limit β for Triangular Distribution relies on the empirical data from DNO's network design. In practice, it is not necessarily the same parameters for α and β between different LV networks. Therefore, in this section, the variation of reinforcement costs because of variation of parameters for triangular distribution is investigated. Figure 7-10 shows the variation of reinforcement costs via the variation of the parameters. It can be observed that with a small variation of the both parameters, there is reasonable change on reinforcement costs. However, if the variation of parameters continues, the trend shows the change of reinforcements tends to be great. Therefore, carefulness should be given on the choice of the parameters. Practical data is recommended as a reliable source for these parameters. It should be noted that the range of α and β is 0~1, which stands for the utilisation of network assets in Figure 7-10.

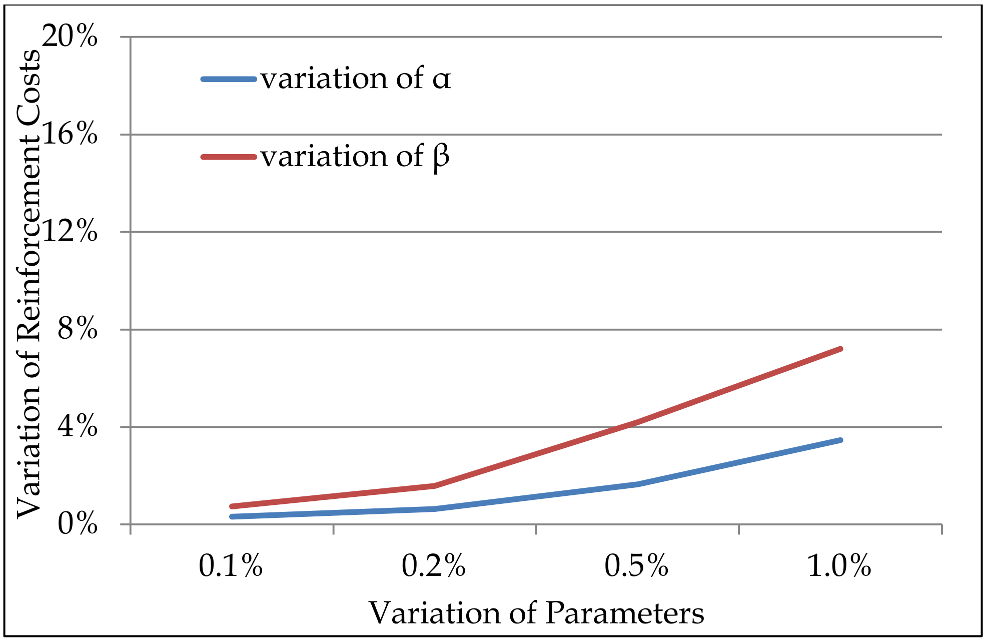


**Figure 7-10 Sensitivity Study of Parameters on Triangular Distribution**

## 7.5 Chapter Summary

This chapter presents a novel statistical approach to approximate future LV reinforcement costs due to demand growth. The cost results are compared with the published past year's reinforcement costs by DNOs. Based on the detailed analysis, the following major observations can be done:

1) The proposed approach provides an alternative when detailed load flow calculation cannot possibly be applied to large and extensive LV networks to quantify the reinforcement costs at the system level;

2) The triangular distribution can estimate the condition of LV networks on a very large scale by making the most use of limited available data from networks;

3) LV networks are categorised into urban, suburban and rural areas by the proposed approach utilising the limited information available, reflecting the characteristics of demographical and network information in different regions in the evaluation of reinforcement activities;

4) The resulting costs are comparable to the reinforcement costs required in a recent year published by Ofgem. Therefore it can be concluded that the proposed approach has successfully achieved the initial objective and therefore provides a useful tool in the preparation stage for long-term LV distribution network planning;

5) Load growth rates and the parameters of triangular distribution both play important roles in evaluating the reinforcement costs using the approach in this study.

The proposed approach is ideally suited for evaluating future investment cost in a LV network with very limited sensory information. With increasing deployment of smart meters, more detailed load information at end users will become available. This will be extremely valuable for refining the parameters used in the proposed planning tool to model the system loading levels, i.e. the minimum, maximum and averaging loading conditions of the LV network assets. Furthermore, more accurate demand information will inform the development of more representative probabilistic distribution of assets utilisation, which can significantly improve the accuracy of the long-term LV network investment evaluation.

Future works can be carried out in two areas to enhance the applicability of the proposed approach in two areas:

1) In this study, the load growth rate is assumed the same in urban, suburban and rural areas. However, in practice, the rates of demand growth in urban, suburban and rural areas may be different, it would therefore be more appropriate to use differing load growth rates in the three areas, and potentially be able to differentiate load growth between existing customers and new connections;

2) The current implementation assumes that there is a suitable amount of empirical data available for the parameters of the triangular distribution to be accurate estimated; further work will focus on incorporating additional sensory information provided by advanced meters or inherent uncertainties of empirical

data to enhance the accuracy of representative for LV networks by triangular distribution.

# Chapter 8

# Use of System Charges for Large-Scale LV Networks: Average Reinforcement Cost

## 8.1 Introduction

The reform is undergoing for use of system charges for EHV distribution networks by implementing either the LRIC or FCP model. They are considered by the industry as the best available approaches to achieve the high level charging principles for EHV distribution networks: cost-reflectivity, simplicity and predictability. However, due to the complexity of the two economic charging methodologies, it is agreed by the industry that the current DRM pricing model is retained for the HV/LV network charging. As stated in Chapter 3, the drawbacks of DRM make it necessary to develop new charging methodologies that can encourage the efficiency use of the HV/LV networks. Meanwhile, it is thoroughly discussed in Chapter 3 that cost reflectivity criterion can be addressed in two different manners, i.e. 'total' and 'incremental'.

In this thesis, two different new charging methodologies are proposed, reflecting the aforementioned different cost reflectivity manners. This chapter commences the Average Reinforcement Cost (ARC) methodology firstly and then it is followed by the Long Run Incremental Cost (LRIC) in Chapter 9.

## 8.2 Principle of ARC model

The basic principle of ARC is firstly to forecast the expected demand into the near future, and then to estimate the system requirements over time to meet the expected demand levels as well as the corresponding required costs. Finally, ARC is calculated by the expected costs divided by the expected demand on an average basis. In this study, reinforcement activities are identified with a 10-year horizon. This is achieved by incrementing the loads, taking account of the forecasted load growth in each year provided by DNO's LTDS. The future reinforcement costs over the 10-year planning horizon are then quantified using the proposed statistical approach in Chapter 7. The approach can reach an agreement with the cost reflectivity requirement suggested by Ofgem, i.e. network charges should reflect the investment costs that will be incurred in the future rather than on costs incurred historically.

The process of the new charging model can be summarised as:

1. Approachable data collection for LV distribution networks;

2. Categorising LV networks into urban, suburban and rural networks using the approach presented in Chapter 6;

3. Setting up the statistical model for each subarea in step 2 using the approach proposed in Chapter 7;

4. Estimating the required reinforcement costs for each subarea due to certain load growth rate over a long term planning horizon, for example, 10 years in this study;

5. Identifying the expect demand for each subarea;

6. Calculating the unit cost for each subarea by allocating the overall reinforcement costs into the expected demand;

7. Weighted average cost could be recommended and calculated for LV networks in this study due to simplicity purpose;

## 8.3 Formulation of Deriving Unit Cost

### 8.3.1 Setting Up the Low Voltage Network Model

According to the statistical approach presented in the Chapter 7, it is necessary to build up the statistical model representing LV network usage condition using triangular distribution firstly. The data available for LV networks to form the statistical model includes system assets costs, the number of assets and peak demand, etc.

### 8.3.2 Predicted Load Growth Rate

The load growth rate plays an important role in distribution network planning, which is also considered as one of the key factors in network pricing for distribution networks. Load growth rate directly affects the evaluation of future reinforcement costs. Therefore, it is necessary to predict carefully the long-term load growth rate. In this study, the load growth rate provided by LTDS from DNOs is used.

### 8.3.3 Future Reinforcement Costs

Reinforcement costs can be identified using the approach proposed in Chapter 7 for a specific planning horizon. The reinforcement activities are firstly identified by both thermal violation and voltage violation. The number of assets to be reinforced is then calculated and thereafter, the reinforcement costs are forecasted. Contingency Analysis is not considered for LV distribution network for simplicity purpose.

### 8.3.4 Annuity Factor and Discount Rate

Annuity factor is used to annualise the total estimated costs, which can be calculated as in (8-1):

$$AnnuityFactor = \frac{1}{(1/r) - 1/(r \times (1+r)^n)} \tag{8-1}$$

The annuity factor reflects the rate of return $r$on the investment over $n$ years.

The net present value of the future reinforcement cost for the network is calculated using a discount rate, which is equal to the cost of capital assessed by Ofgem as part of the price control. Currently, the discount rate is taken as 5.6%.

### 8.3.5 Unit Costs for Each Area in LV Networks

For each subarea, the future reinforcement costs are averagely allocated to the predicted future demand, which are regarded as unit costs (£/kW/year) for the target area, described as (8-2):

$$UnitCost = \frac{Cost/(1+d)^n}{D} * AF \tag{8-2}$$

where *Cost* is the reinforcement cost over the planning horizon, *n* years; *d* is discount rate; *D* is the predicted demand at the $n_{th}$ years; *AF* is Annuity factor.

### 8.3.6 Weighted Average Unit Cost for Whole LV Network (Optional)

Weighted average unit cost is introduced as the final unit cost for the whole LV network when the zonal charges for different areas are not applicable and difficult to be implemented in practice. The equation is shown as (8-3)

$$UnitCost\_final = \frac{\sum P_i \cdot D_i}{\sum D_i} \tag{8-3}$$

where $P_i$ is the unit cost for the area *i* in the LV network and $D_i$ is the demand in the area *i*.

## 8.4 Demonstration on a Practical Network

### 8.4.1 Network Profile

In this section, the proposed ARC model is demonstrated on a practical LV network from the UK, which is owned by one of the DNOs, Western Power Distribution (formerly Central Networks). The total peak demand connected at CN East LV network is 3740MW with a power factor 0.95. The Low Voltage network is designed as radial feeders from 11kV/0.4kVdistribution substations. The total capacity of transformers is 11709MVA.

### 8.4.2 Results Analysis

#### 8.4.2.1. Future Reinforcement Costs

The future reinforcement costs are estimated for 10 years for the LV distribution network using the proposed statistical approach in Chapter 7. The rationale for using a 10-year horizon is that it is consistent with the LTDS growth assumptions. Load growth rate is taken as 2.1% per year, which is the predicted load growth rate for the LV network by DNO[94]. The current year is assumed as 2010 and the study period lasts until 2020.

As stated previously to quantify large-scale LV networks reinforcement costs, the network is categorised into urban, suburban and rural areas in order to recognise the network condition properly in the first place. Thereafter, the reinforcement cost for each subarea is derived respectively. The results are shown in Table 8-1. It can be expected that the reinforcement costs over 10 years vary between urban, suburban and rural areas. The present value of the predicted reinforcement costs are also given in Table 8-1, by taking account of discount rate as 5.6% [96].

**Table 8-1 Future Reinforcement Costs for Urban, Suburban and Rural Areas (2010 to 2020, r= 2.1%)**

| | Reinforcement Costs (£) | Present Value--Reinforcement Costs (£) |
|---|---|---|
| Urban | £446,058,260 | £258,673,776 |
| Suburban | £47,772,362 | £27,703,685 |
| Rural | £3,308,964 | £1,918,902 |

8.4.2.2. **Predicted Demand**

The predicted demand over 10 years is calculated by applying the predicted load growth rate, 2.1% per year, based on current demand level. It is assumed that the load growth rate encompasses the overall growth trend of demand regardless of the difference between urban, suburban and rural areas. The calculated future demand is shown in Table 8-2 along with the current demand as well as the incremental demand. It can be noticed that over the 10-year period from 2010 to 2020, the magnitude of demand growth in urban area is much larger than those in the other two, especially in rural area, which is up to 736 MW under the predicted load growth rate in the LV network. Therefore, it is anticipated that more reinforcement activities could be expected in the urban area than suburban and rural areas, which makes the agreement with the results in Table 8-1.

**Table 8-2 Demand Connected at CN East LV network in 2010 and 2020 (r = 2.1%)**

| | Demand in 2010 (MW) | Demand in 2020 (MW) | Incremental demand (MW) |
|---|---|---|---|
| Urban | 3185 | 3920 | 736 |
| Suburban | 2511 | 3091 | 580 |
| Rural | 429 | 528 | 99 |

8.4.2.3. **Unit Cost**

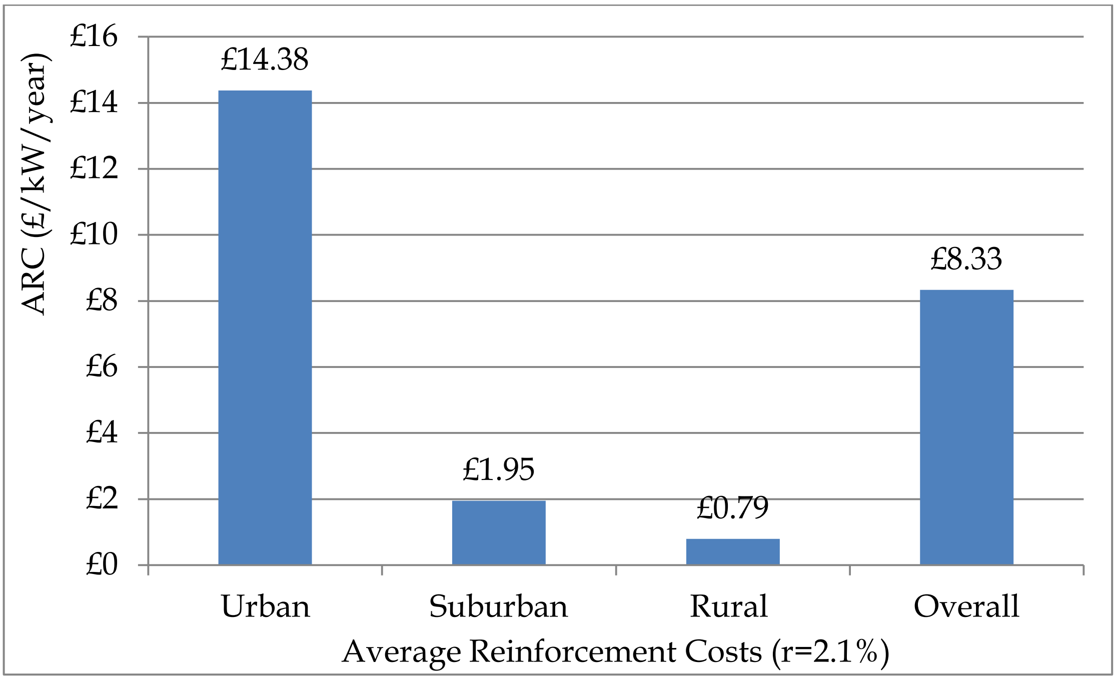


**Figure 8-1 Unit Costs for Central Network East Low Voltage Networks (r=2.1%)**

The unit costs (£/kW/year) for each subarea is obtained by allocating reinforcement costs to the predicted demand in each subarea, taking account of annuity factor and discount rate.

Figure 8-1 depicts the average unit costs for urban, suburban and rural areas of the LV network. The charge in urban area is up to £14.38/kW/year whereas in rural area it is only 0.79£/kW/year. The charges reflect the large variation of network usage condition in urban, suburban and rural area. On the one hand, from the statistical model set up for the three areas in the previous chapter (Figure 7-5, 7-6 and 7-7), it can be observed that the higher utilisation of urban area network indicates that lower spare capacity compared with the suburban and rural areas. Therefore, higher charges for customers in urban areas while lower charges for customers in rural areas are expectable. On the other hand, the asset costs in urban area are much more expensive than the one in the rest of areas.

As mentioned before, in practice, it is less fair and practical to impose the three different charges to customers just because of their geographical connection. Besides, charges for certain customers are sensitive to the boundaries, which are used to categorise the LV network into urban, suburban and rural areas. Therefore, an overall average weighted price, £8.33/kW/year, is recommended for DNOs to charge their customers as show in Figure 8-1.

The overall average cost for customers connected in LV networks can eliminate discrimination to some extent. The network usage condition is recognised by the proposed reinforcement evaluation method, which is regarded as cost reflective.

#### 8.4.2.4. **Charges under Different Load Growth Rates**

Since load growth rate plays an important role in deriving future reinforcement costs in the proposed charging model, different load growth rates are considered in this section to see how the network charges vary with different load growth rates. Load growth rate ranging from 1.2%, 1.5%, to 1.8% per year is separately considered in the reinforcement cost model.

Table 8-3 provides the calculated reinforcement costs over the future 10 years period from 2010 to 2020 under load growth rate at 1.8% per year. Correspondingly, the unit costs for urban, suburban and rural areas along with the overall average cost for the LV networks in Figure 8-2. It can be observed that either the charges in each area or the overall average charge for the whole LV networks are less than the ones under load growth rate at 2.1% per year. It can be explained by that larger load growth rate need more network usage, which result in higher reinforcement costs due to more reinforcement activities.

**Table 8-3 Reinforcement Costs for Urban, Suburban and Rural Areas (2010 to 2020, r= 1.8%)**

| | Reinforcement Costs (£) | Present Value--Reinforcement Costs (£) |
|---|---|---|
| Urban | £318,852,174 | £184,905,658 |
| Suburban | £41,469,891 | £24,048,816 |
| Rural | £3,040,320 | £1,763,113 |

**Table 8-4 Demand Connected at CN East LV network in 2010 and 2020 (r = 1.8%)**

| | Demand in 2010 (MVA) | Demand in 2020 (MVA) | Incremental demand (MVA) |
|---|---|---|---|
| Urban | 3185 | 3807 | 622 |
| Suburban | 2511 | 3001 | 490 |
| Rural | 429 | 512 | 84 |

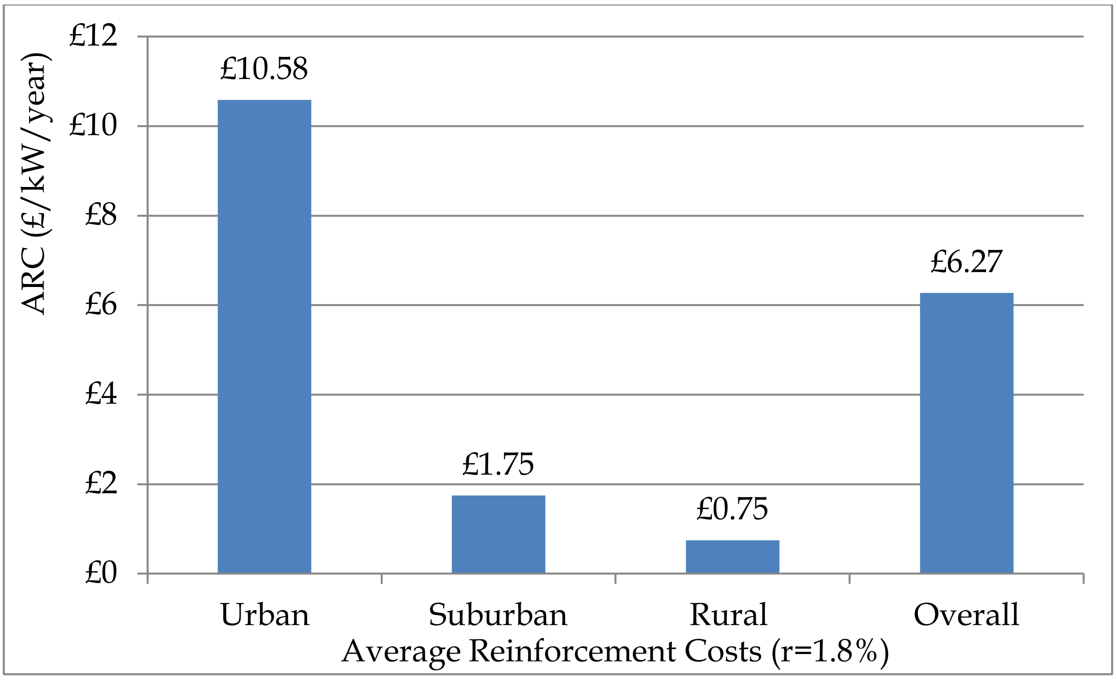


**Figure 8-2 Unit Costs for Central Network East Low Voltage Networks (r=1.8%)**

In order to illustrate the impact of load growth rate on network charges derived in the proposed approach more vividly, lower load growth rates, 1.5% and 1.2% are again considered. Figure 8-3 shows the unit cost for urban, suburban and rural area as well as the overall final cost for the whole LV network with load growth rate 1.5%. Compared with the unit cost in urban area up to £14.38/kW/year under load growth rate at 2.1% each year, the unit cost is down to £4.73/kW/year if the load growth rate is 1.2% as shown in figure 8-4. The same pattern of charges appears in suburban and rural areas and the overall average costs are no exception. The overall average cost is £8.33/kW/year and £6.27/kW/year under load growth rates 2.1% and 1.8% respectively, whereas under 1.5% and 1.2%, the overall average cost is £4.45/kW/year and £2.97/kW/year.

Therefore, it can be concluded that

1. Higher charges will be given for urban areas, which have the less spare capacity compared with suburban and rural areas;
2. Charges are especially high for the area with higher utilisation and load growth, which could discourage underlying demand increase;

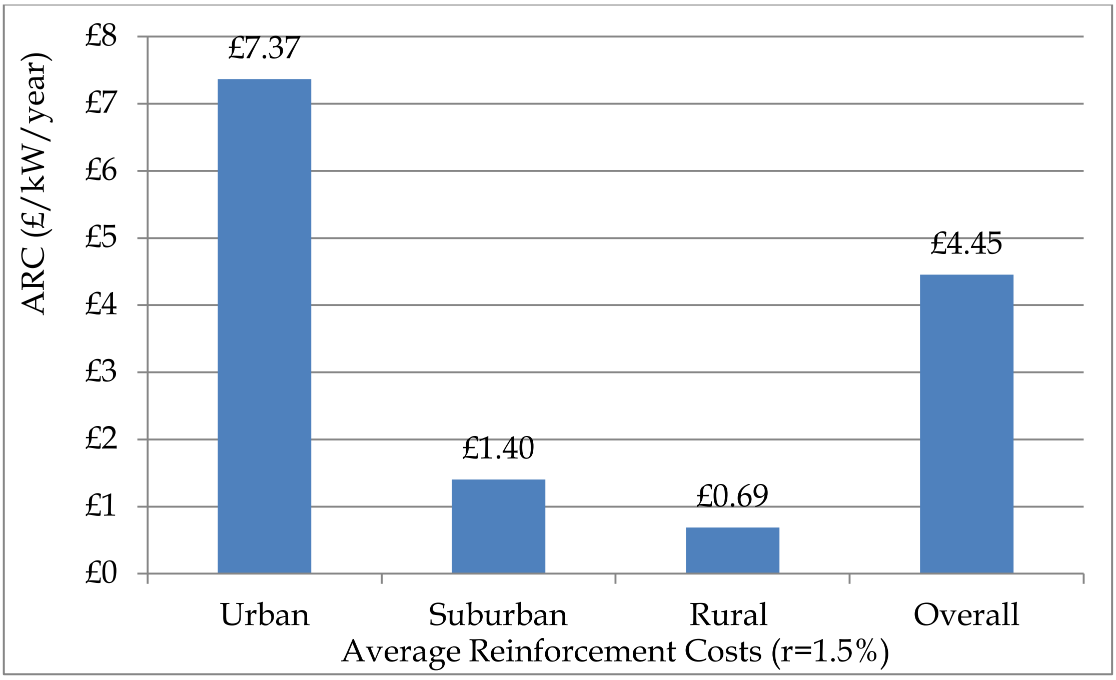


**Figure 8-3 Unit Costs for Central Network East Low Voltage Networks (r=1.5%)**

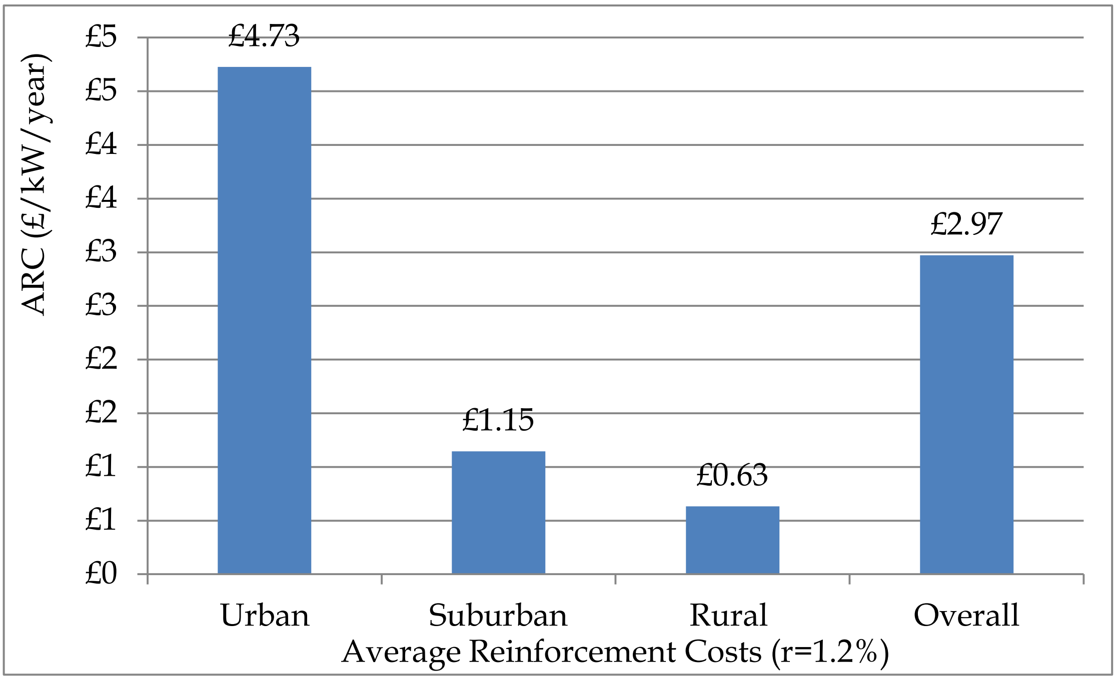


**Figure 8-4 Unit Costs for Central Network East Low Voltage Networks (r=1.2%)**

## 8.5 Summary of Key Strengths and Concerns of the ARC Model

This charging model use publicly available data to derive charges for demand in LV distribution networks. It is forward-looking in nature as it uses published demand growth forecast to assess the volume of additional necessary investment by the DNO in the future. The method can recognise those areas of the LV network where there is more spare capacity in terms of lower network assets utilisation, which is likely to remain partially unutilised into the future and therefore lower charges could be given. Conversely, in those areas of the network with higher assets utilisation, additional reinforcement activities are required in the near term on account of growth in demand, which results in higher charges. Since, charges derived from the method proposed are considered cost reflective in the forward looking sense. This might impact on either DNOs or customers considering planning decision or connecting to the network.

By reviewing this methodology against the criteria that Ofgem prefers in its assessment, the following strengths of this model can be identified:

1. The extensive of use of publicly available data;

   Inputs into the methodology to calculate the charges are taken from publicly available data such as the Long Term Development Statement or National Statistics. The fact can ensure that the methodology is transparent to some extent and charges are therefore predictable to a large extent.

2. The derivation of charges on a basis of the recognition of different utilisation levels of network;

   Charges are derived for the LV network based on the recognition of different utilisation levels of the network and therefore can reflect the underlying network usage conditions, which is regarded as being cost reflective.

In our study, the overall weight average cost is recommended at the final stage for the LV network, it is acknowledged that the average cost could offset the enhancement of cost reflectivity criterion by locational charges. However, the more detailed zonal locational signals in LV networks would substantially increase the complexity and require more engineering-based judgement to derive charges with minimal incremental benefit arising from the additional cost reflectivity that this could create.

3. The methodology is relatively simple to understand;

4. Implementation costs are likely to relatively low.

In addition to these strengths mentioned above, some concern is also identified.

1. The charges derived from the proposed methodology are not fully reflective of the incremental cost of expected future reinforcement.

   It is agreed by researchers and industrialists that tariffs should ideally reflect the incremental cost of reinforcement in order to encourage efficient decision-making. Charges derived from the proposed approach are to some extent average charges rather than incremental cost.

2. The charges have relatively weak locational signals especially when weighted average costs are suggested.

## 8.6 Chapter Summary

A novel charging model for LV distribution networks is proposed in this chapter. The principle of this model is that the revenue recovery generated from its charges is equal to the expected cost of reinforcement, which can be quantified using the proposed statistical approach. The unit costs are derived by allocating the reinforcement costs on an average basis, which is cost reflective averagely. The key features and potential concerns of this charging model have been summarised after extensive analysis.

# Chapter 9

# Use of System Charges for Large-Scale LV Networks: LRIC

## 9.1 Introduction

As indicated in Chapter 8, this chapter presents a charging model for LV networks in terms of reflecting the 'incremental' cost, in contrast to 'total' cost. The LRIC method for LV networks takes the key principles of LRIC for EHV networks developed by University of Bath teamed with Western Power Distribution Company.

The LRIC for EHV networks originally produces forward-looking charges that reflect the cost of advancing or deferring future reinforcement consequent upon the addition of generation or load at each node in the manner of nodal injection or withdrawn. However, for LV networks it is not practically to conduct the same simulation process in each node with nodal injection or withdrawn as EHV networks because the extensive of network configuration and lack of data. Therefore, the LV network is categorised into several areas according to different utilisation levels. In each area with the same utilisation degree, the utilised capacity or headroom can be used to gauge the length of time before the reinforcement is required. To achieve this, the triangular distributions representing the condition of the entire network assets in LV networks, are adopted in this chapter.

Moreover, instead of using additional nodal injection or withdrawn for EHV networks, the incremental cost for the LV network is evaluated by recognising the advancing or deferring future reinforcement consequent upon load growth rate variation. This is to indicate the impact of underlying load growth rate on the future reinforcement. Hence, the charges can potentially provide economic signals for LV customers to control their expansion of load increase. Detailed analysis is given in the following sections.

## 9.2 Mathematical Formulation of the Charging Model

The proposed charging model can be implemented through the following steps:

**1) Derivation of the network cost to support the existing customers with an annual load growth *r***

If a LV network has an average utilisation of *U*, then the number of years it takes to grow from *U* to full utilisation *'1'* for a base annual load growth rate *r* can be determined from (9-1)

$$1 = U \times (1+r)^{n_{old}} \tag{9-1}$$

where *U* is the average utilisation of the network, $n_{old}$ is the number of years U reaches '1'.

Rearranging (9-2) gives the value of $n_{old}$

$$n_{old} = \frac{-\log U}{\log(1+r)} \tag{9-2}$$

It is assumed that reinforcement will occur when the LV network is fully utilised. Thus, investment will occur in $n_{old}$ years when the network is fully utilised. It should be noted that the load growth rate *r* could be regarded as the 'ideal' load growth set during network planning stage by DNOs.

**2) Evaluating the present value of future reinforcement cost**

The future investment can be discounted back to its present value, which will be a function of how far into the future the investment will be made. If a discount rate of *d* is chosen, then the present value of the future investment in $n_{old}$ years will be

$$PV = \frac{Asset}{(1+d)^{n_{old}}} \tag{9-3}$$

where *Asset* is the modern equivalent asset cost of the LV network.

**3) Evaluating the increment cost because of an small variation of load growth rate $r+\Delta r$ of the network**

Load growth rate might not be the same as the predicted one, because of either the existing customer's expansion or different sizes of new customers to be connected in LV networks in the future. Thus, as a result of $\Delta r$ over the future years, the forward future investment will be brought from year $n_{old}$ to $n_{new}$.

$$1 = U \times (1 + r + \Delta r)^{n_{new}} \tag{9-4}$$

Therefore, the present value of future investment is affected as

$$PV_{new} = \frac{Asset}{(1+d)^{n_{new}}} \tag{9-5}$$

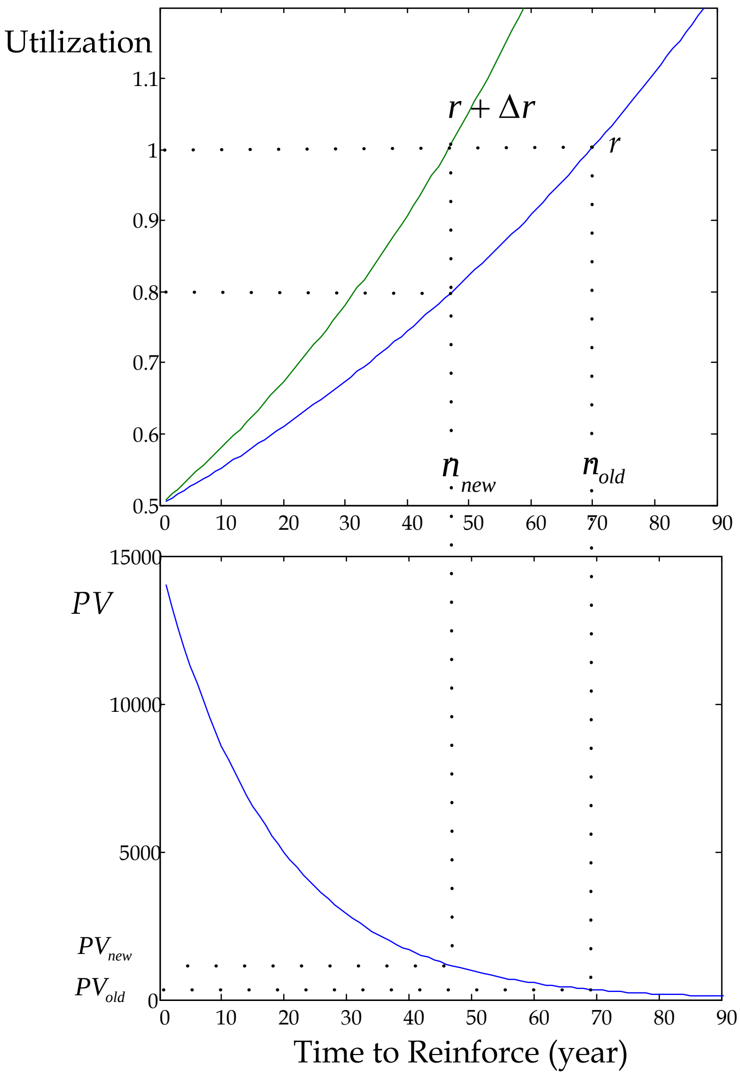


**Figure 9-1 Changes of Present Value due to Load Growth Rate Variation**

The change in the present value as a result of the load growth rate variation, as illustrated in Figure 9-1, is given by (9-6)

$$\Delta PV = PV_{new} - PV_{old} = Asset \times \left(\frac{1}{(1+d)^{n_{new}}} - \frac{1}{(1+d)^{n_{old}}}\right) \tag{9-6}$$

The annualised incremental cost of the network is the difference in the present value of the future investment because of load growth rate variation by an annuity factor.

$$IC = \Delta PV \times annuityfactor \tag{9-7}$$

**4) Implementing the approach into LV distribution networks**

As discussed in Chapter 6, LV distribution networks can be categorised into three subareas, i.e. urban, suburban and rural network. Thereafter, for each subarea, the utilisation of system assets (transformers/circuits) can be estimated as shown in Figure 9-2 using triangular distribution (detailed analysis is given in Chapter 7).

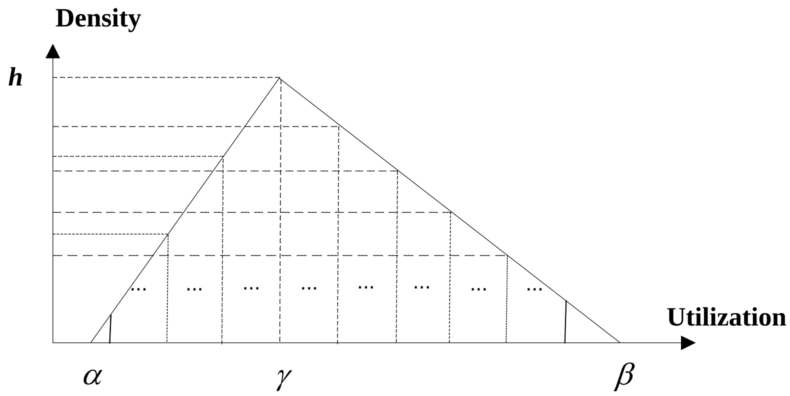


**Figure 9-2 Triangular Distribution of LV Networks Utilisation**

It can be observed that the utilisation of system assets is utilised at various levels ranging from the lower α to the upper β.

To implement the proposed charging methodology in each subarea, discretisation points are applied into the distribution to categorise the entire LV networks into limited assets groups with different utilisation levels as shown in Figure 9-2.

For each assets group with the similar utilisation level, the approach presented from step 1) to step 3) can be applied. Therefore, there will be $IC_i$ for asset group *i*. For the whole LV network, the total incremental costs can be

$$IC_{total} = \sum_{i=1}^{m} IC_i \tag{9-8}$$

**5) Calculating the unit cost for the LV network**

The unit cost to the LV network is the summation of the incremental cost over the total incremental load ΔD resulted from the variation of load growth rate over the years to reinforce the network, given by (9-9)

$$\Delta D = C \times \left(\frac{1}{(1+r)^{n_{new}}} - \frac{1}{(1+r+\Delta r)^{n_{new}}}\right) \tag{9-9}$$

The incremental load ΔD can also be illustrated in terms of increased utilisation in Figure 9-1.

Therefore, the long run incremental cost is given by (9-10)

$$LRIC = \frac{IC_{total}}{\Delta D} \tag{9-10}$$

## 9.3 Demonstration on a Practical Network

### 9.3.1 Network Profile

In this section, the method proposed in this chapter is demonstrated on a practical LV network from the UK, which is owned by one of the DNOs, Western Power Distribution (formerly Central Networks). The total peak demand connected at CN East LV network is 3740MW with a power factor 0.95. The Low Voltage network is designed as radial feeders from 11kV/LV distribution substations. Load growth rate is taken as 2.1%.

### 9.3.2 Distribution of Assets Utilisation using Triangular Distribution in Subareas

The statistical model representing assets utilisation in each subarea has been developed in Chapter 7, shown in Figure 7-5, 7-6 and 7-7. As stated in Step (4) of the proposed LRIC approach for LV networks, in each subarea it is categorised into 10 different utilisation levels, among which the same utilisation is assumed for the assets.

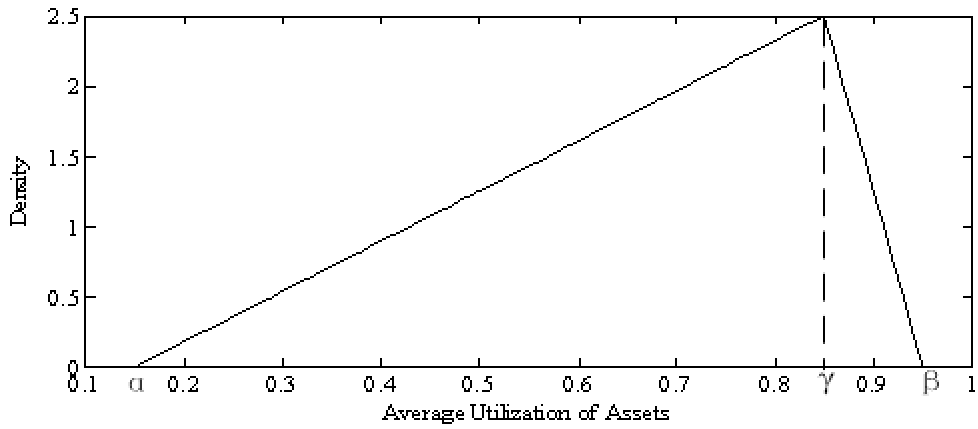


**Figure 9-3 Assets Utilisation in Urban Area**

**Table 9-1 Utilisation Levels in the Urban Area**

| Sub-area | Utilisation | Proportion | Asset Costs (£) |
|---|---|---|---|
| 1 | 19% | 1.14% | 13,128,603 |
| 2 | 27% | 3.43% | 39,385,810 |
| 3 | 35% | 5.71% | 65,643,017 |
| 4 | 43% | 8.00% | 91,900,224 |
| 5 | 51% | 10.29% | 118,157,431 |
| 6 | 59% | 12.57% | 144,414,638 |
| 7 | 67% | 14.86% | 170,671,845 |
| 8 | 75% | 17.14% | 196,929,051 |
| 9 | 83% | 18.86% | 216,621,957 |
| 10 | 91% | 8.00% | 91,900,224 |

Let's take the urban area in the practical network as an example to demonstrate the method. The network utilisation in urban area ranges from 15% to 95%, with the average utilisation is 65%. The network is divided into 10 different utilisation levels as shown in Table 9-1. The proportion of assets in each subarea can be calculated accordingly, along with the asset costs in each utilisation levels by assuming the typical unit costs.

### 9.3.3 Incremental Costs Calculation

**Table 9-2 LRIC Charges for Different Utilisation Levels in the Urban Area**

| Sub-area | Utilisation | Horizon to Reinforcement (years) | New Horizon after Load Growth Variation(years) | Effective Demand Change due to Δr (MW) | Change of Present Value due to Load Growth Variation (£) |
|---|---|---|---|---|---|
| 1 | 19% | 79.9 | 64.7 | 3.8 | 217,742 |
| 2 | 27% | 63.0 | 51.0 | 11.3 | 1,172,724 |
| 3 | 35% | 50.5 | 40.9 | 18.8 | 2,882,296 |
| 4 | 43% | 40.6 | 32.9 | 26.3 | 5,265,201 |
| 5 | 51% | 32.4 | 26.2 | 33.8 | 8,074,199 |
| 6 | 59% | 25.4 | 20.6 | 41.3 | 10,906,412 |
| 7 | 67% | 19.3 | 15.6 | 48.9 | 13,211,563 |
| 8 | 75% | 13.8 | 11.2 | 56.4 | 14,298,781 |
| 9 | 83% | 9.0 | 7.3 | 62.0 | 13,949,904 |
| 10 | 91% | 4.5 | 3.7 | 26.3 | 3,458,194 |

A discount rate of 5.6% is taken in this study, which is the current accepted Minimum Acceptable Rate of Return by the UK's DNOs in setting network charge. Table 9-2 gives the original time horizon of reinforcing network assets and the new time horizon to reinforce because of load growth rate variation. It can be observed that the time to reinforce decreases monotonically as the assets' utilisation increases. Meanwhile, with a load growth rate positive variation '0.5%', the time to reinforce is brought forward, i.e. accelerating the need of upgrading network. In addition, the incremental demand due to $\Delta r$ in each utilisation level can also be computed using (9-9) and shown in Table 9-2. Thereafter, the change of present value of asset costs can be obtained using (9-6).

When the utilisation is low, the cost of accommodating a small load growth rate variation rather than base load growth rate is also low, but as the utilisation approaches '1', the reinforcement becomes imminent and the cost rises to a high level.

By using (9-8) and (9-10), the LRIC charge for urban network can be calculated as £16.35/kW/year. It is noticeable that the final average charge for the whole urban area may exaggerate the low charges in certain areas with low utilisation. However, it is acceptable because of the following reasons:

1. It could be high cost both in time and labour to bring different charges according to the utilisation levels into practice;

2. In the way that the urban area is divided into different utilisation level, the network condition has been recognised properly. Therefore, the network costs can be evaluated effectively. The overall weight average cost could represent the effectiveness although it is abated to some extent compared with the ones specific to different utilisation levels. Moreover, one significant advantage of the overall weight average cost is simple to use, which is high recommended by Ofgem in their guidance for DNOs in setting network charges methodology.

Similarly, the same procedure can be applied into suburban and rural areas to obtain LRIC charges. The final charges for suburban and rural areas are depicted in Figure 9-4. In suburban area, the charge is smaller as £9.7/kW/year compared with the one in the urban area. This is because the assets in suburban area are utilised lower than the ones in the urban area, allowing more load increase before reinforcement is needed. The rural area has the smallest cost among the three areas as £6.9/kW/year.

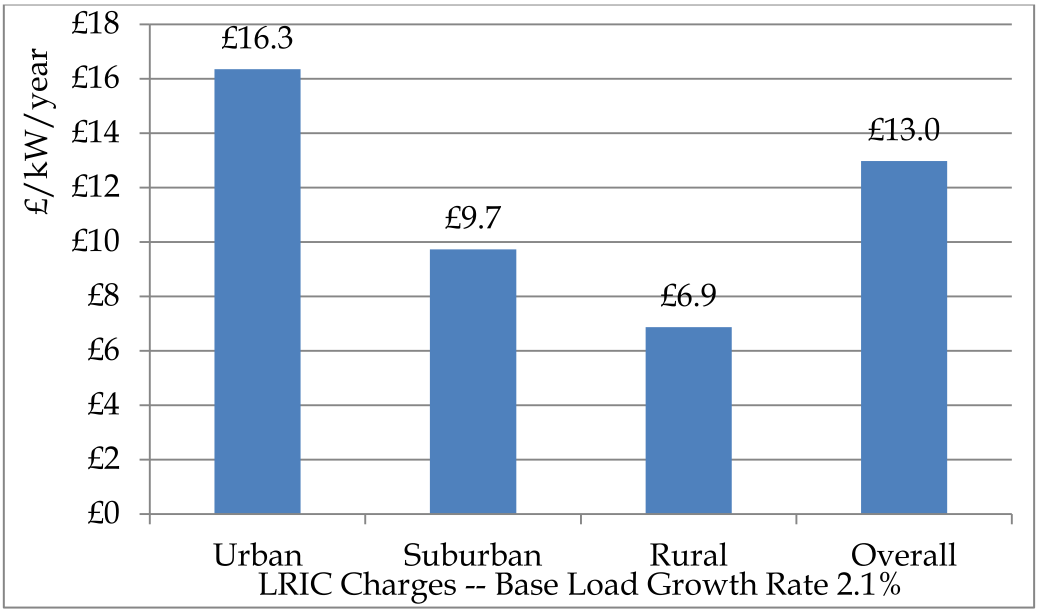


**Figure 9-4 LRIC charges for the LV network (r=2.1%)**

The overall average cost, £13/kW/year, is also recommended for the whole network considering it might not be worthwhile to put the 'locational' or 'zonal' charges into practice for LV networks.

### 9.3.4 Different Base Load Growth Rate

In this section, the impact of base annual load growth rate on LRIC charges is investigated. To do so, different annual load growth rates, 1.8%, 1.5% and 1.2% are separately applied in the proposed method to see how the charges varies. Figure 9-5 illustrates the LRIC charges in urban, suburban and rural areas along with the overall average cost under load growth rate 1.8%. Compared with the ones under load growth rate 2.1%, the charges are slightly decreased in each area. This is because the time to reinforcement can be deferred under load growth rate 1.8% compared with 2.1%, which therefore results in the decreased present value of asset costs.

The same pattern and trend happens when the load growth rates are 1.5% and 1.2%. Table 9-6 and Table 9-7 provides the LRIC charges for urban, suburban and rural areas as well as the overall average cost for the whole LV network under load growth rate 1.5% and 1.2% respectively.

Overall, with the base load growth rate ranging from 2.1%, 1.8%, 1.5% to 1.2%, the difference between these incremental charges derived under different load growth rates appears no significant distinction. The fact indicates the marginal price that has been derived properly to reflect the network usage condition.

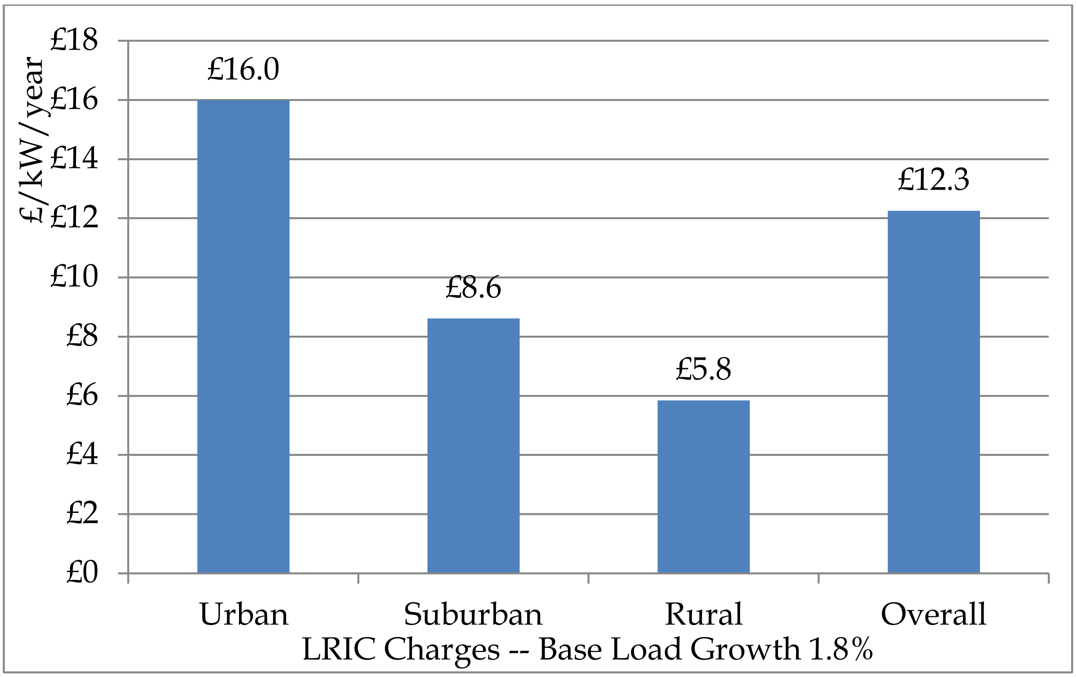


**Figure 9-5 LRIC charges for the LV network (r=1.8%)**

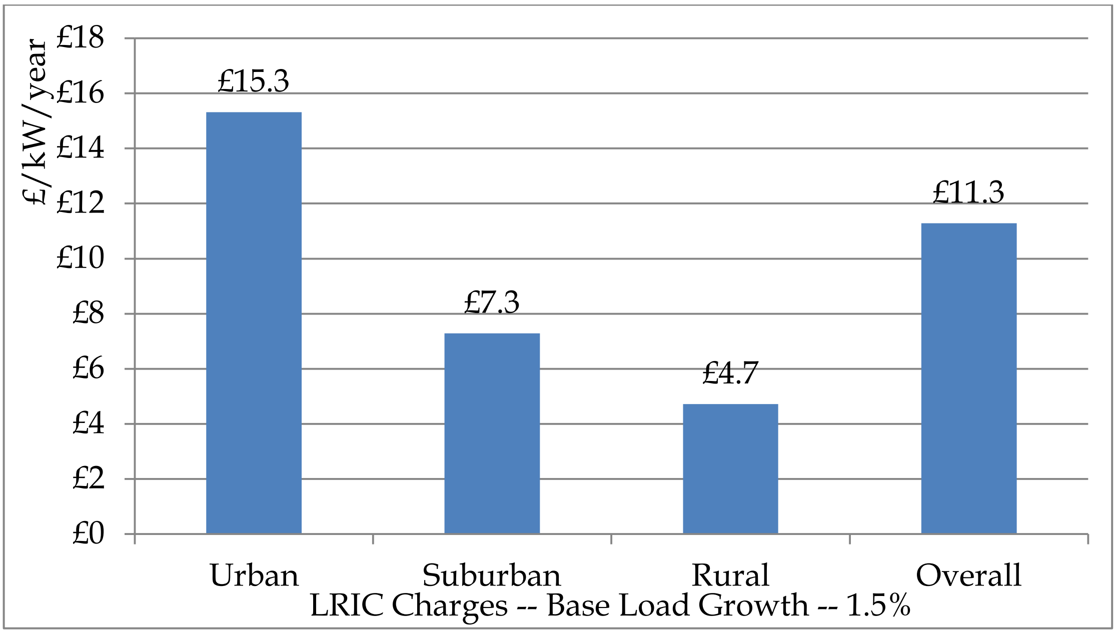


**Figure 9-6 LRIC charges for the LV network (r=1.5%)**

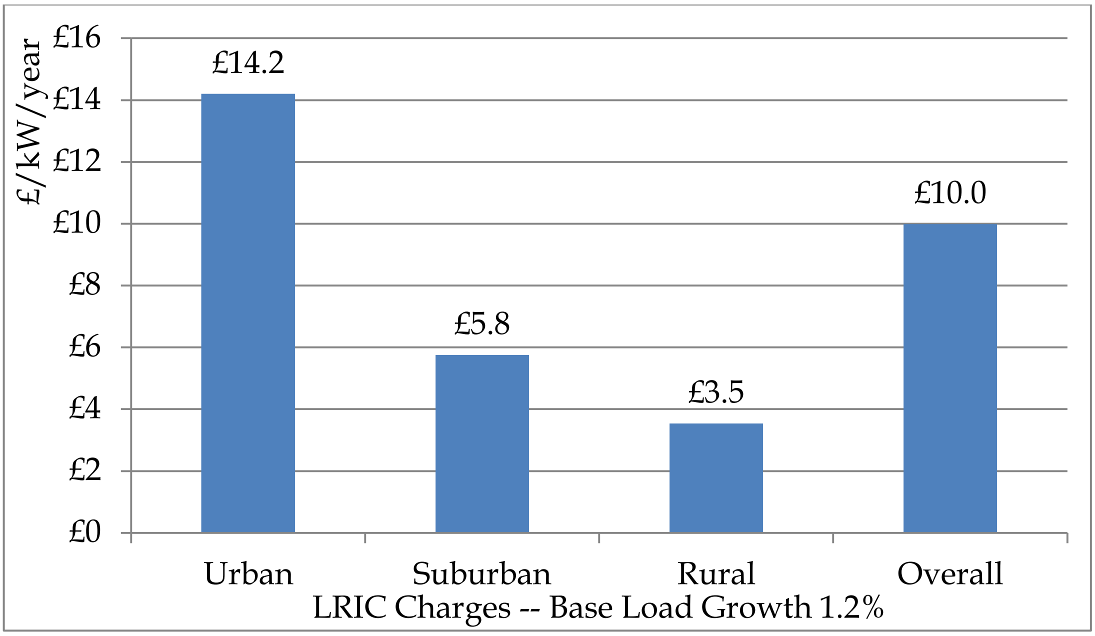


**Figure 9-7 LRIC charges for the LV network (r=1.2%)**

## 9.4 Compared with the ARC Model

In comparison, the LRIC model is an incremental cost pricing approach whereas the ARC is more in favour of a total cost pricing approach.

In terms of economic theory, cost based on LRIC theoretically provides the foundation for efficient use of existing system capacity as well as efficient capital investment in future capacity. In contrast, the ARC model has the potential of sacrificing economic efficiency as a result of departing from the pure incremental cost pricing. However, both of the charging models are based on future investment costs rather than past or historic costs, which can provide forward-looking price signals.

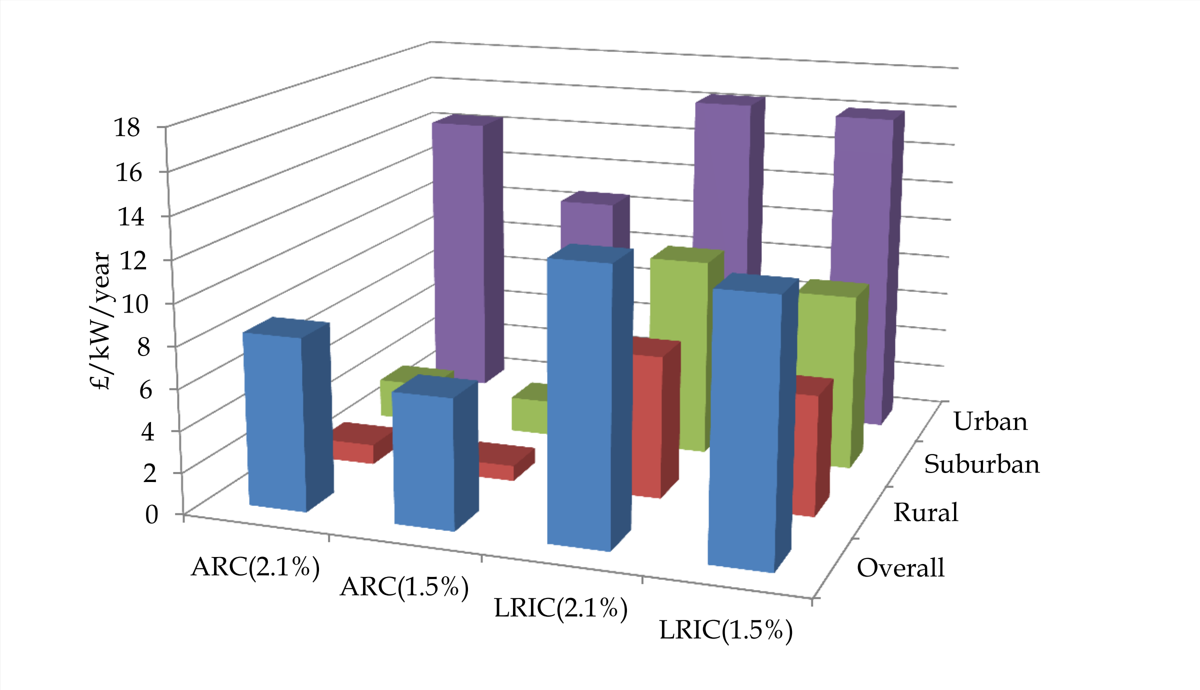


**Figure 9-8 Comparison between ARC and LRIC under Different Load Growth Rate**

In terms of charges, charges from both of the charging models are sensitive to utilisation levels and load growth rates. The charges can reflect the level of spare capacity on the existing network. Specifically, charges are higher for the urban area with higher utilisation and larger load growth rate. Nevertheless, charges provided from the LRIC model decrease slightly with load growth rate decreasing as shown in Figure 9-8. The reason is that LRIC model more reflects the real network utilisation and less relies on the future reinforcement costs. In comparison, with load growth rate decreasing, charges from the ARC model are reduced dramatically, especially in urban area as illustrated in Figure 9-8. This is because that the load growth rate has a large impact on the required future reinforcement costs, which could result in the impact on the final unit charges. Therefore, when using ARC approach, accurate predicted future demand is necessary.

## 9.5 Chapter Summary

This chapter presented a charging model for LV networks in terms of 'incremental' cost reflectivity manner. The charging model takes the key principle of LRIC for

EHV distribution networks, which cannot be directly employed in LV networks due to the extensiveness of network structure and lack of data. With statistical approach representing the utilisation of LV networks, incremental cost can be obtained by evaluating the advancing or deferring future reinforcement consequent upon load growth rate variation.

In addition, the two charging model, the ARC and the LRIC are compared in principle and discussed in this chapter.

# Chapter 10

# Conclusions

Under the deregulated and privatised environment, network charging models play an important role in recovering investment costs for distribution networks from their users. Generally, the desirable network charging models should meet the following charging principles: cost reflectivity, simplicity and predictability.

Presently in the UK, different DUoS charging methodologies are designed according to voltage levels. For EHV distribution networks, LRIC and FCP have been considered by the industry as the best available approaches to achieve the aforementioned principles. Both LRIC and FCP for EHV networks require a full AC load flow and contingency analyses to determine the time to reinforce network assets. They offer more cost-reflective assessment of future reinforcement at the cost of significantly more complicated power flow analysis. However, network configuration in HV/LV networks is extensive and therefore power flow tools are deemed too complicated to be practical for these networks.

Under these circumstances, Distribution Reinforcement Model (DRM) is utilised to charge lower voltage distribution network users. One major drawback of DRM model is that the evaluated costs for 500MW capacity are simply scaled from the current existing asset costs without recognising the system assets utilisation as well as the impact of future load growth. Furthermore, it is widely recognised by both academic researchers and industrialists that lack of price signal either for customers or DNOs makes DRM impossible to guide future demand and generation development. Overall, the DRM model does not take into consideration the anticipated demand growth and the available capacity of the network but estimates a 'future' reinforcement costs brought by 'hypothetical' demand based on historic data. Hence, the DRM prices are neither 'cost reflective' nor 'forward-looking'. Therefore, the improvement on the effectiveness of the network charging methodology on HV and LV networks has become a concern.

## Investment Deferral Assessment of MGs

With the increasing penetration levels of MGs in distribution networks, appropriate recognition of benefits from MGs on distribution networks becomes necessary. The work in this thesis commences with benefit assessment of MGs on distribution networks in terms of investment deferral. To do so, a method for evaluating investment deferral brought by MGs into distribution networks has been developed. Meanwhile, different MGs allocation approaches in distribution networks are considered to find out their impact on investment deferral. The results show that allocating MGs in proportion to LRIC nodal charges is more desirable as it brings the more benefits to network investment. The results also indicate cost reflective network charging model can provide efficient price signals for MGs to obtain great benefits in terms of investment deferral. The work in this chapter provides the basis of future work in developing cost reflective financial schemes.

### Network Pricing for High Voltage Distribution Networks

In order to overcome the drawbacks of DRM discussed above, a new charging methodology for HV distribution networks is developed. The principle of the proposed model is to allocate the future reinforcement costs due to load growth among customers according to their 'extent of use'. To do so, the future reinforcement activities are firstly investigated considering thermal violation and voltage violation, respectively. The final charges show that the charges can reflect the extent of use of network: the more assets are used by load, the higher charges are given. Therefore, the charging model can provide efficient economic signals to demand/generation for their decisions.

### The Approach to split LV distribution networks into Urba/Suburban/Rural

Different from HV distribution networks, it is not practical and worthwhile to give locational charges bus by bus for LV distribution networks because of their extensiveness, which potentially brings about huge computation burden. Therefore, the proposed charging model for HV distribution is not desirable for LV distribution networks. And modelling LV networks' condition properly becomes a concern.

The work in this thesis propose an approach to categorise large-scale LV networks into urban, suburban and rural areas due to the various characteristics of demographical and network information in different local areas. In doing so, load densities, which are not publicly available, are determined by making use of potential approachable data. Meanwhile, the available network assets data is generally held at the aggregated system level, such as the total number of transformers and length of cables and overhead lines, etc. Therefore, disaggregation of the network assets into urban, suburban and rural area is also carried out in this thesis. Overall, this work is the basis of work to evaluate LV network reinforcement costs due to demand growth as well as LV distribution network charges in the following chapters.

**Future Reinforcement Costs Quantification for LV networks using Statistical Approach**

Triangular distribution function is considered to be utilised to quantify the long-term LV distribution network reinforcement costs driven by demand growth. Firstly, the rationale of using triangular distribution over the other functions has been discussed in detail in this thesis. It can be used to estimate the condition of LV networks on a very large scale by making the most use of limited available data from DNOs. The proposed approach provides an alternative when detailed load flow calculation cannot possibly be applied to large and extensive LV networks to quantify the reinforcement costs at the system level. The final resulting costs are comparable to the reinforcement costs required in a recent year published by Ofgem. Therefore, it can be concluded that the proposed approach has successfully achieved the initial objective. The work provides a useful tool in the preparation stage for long-term LV distribution network planning.

**Network Charging Methodologies for Large-scale LV Distribution networks: Average Reinforcement Cost**

Two different new charging methodologies for LV distribution networks are proposed, which take advantage of different cost reflectivity manners.

The principle of ARC is firstly to forecast the expected demand into the near future, and then to estimate the system requirement over time to meet the expected demand levels as well as the accordingly costs. Finally, ARC is calculated by the expected demand divided by the expected costs in an average manner.

The flowchart of this charging model is similar to FCP for HV/LV distribution networks, discussed in literature review. However, the significant improvement appears in the calculation of future reinforcement costs. In FCP, the future reinforcement costs are simply scaled from historic data rather than considering the real network condition as well as future development.  In contrast, in the proposed charging model, the future reinforcement costs are obtained using the statistical approach, better recognising network condition as well as future load growth.

Furthermore, higher charges are given for the customers, who utilise assets with less spare capacity as additional reinforcement activities are required in the near future. Conversely, lower charges are allocated for the customers, who are connected to the network with more spare capacity in terms of lower network assets utilisation. This might impact on either DNOs' planning decisions or customers' choice of connection.

The main concern of the ARC model is that the charges are not fully reflective of the incremental cost and therefore have light economic signals.

## Network Charging Methodologies for Large-scale LV Distribution networks: LRIC

The principle of an alternative charging model for LV networks takes advantage of the key principles of LRIC for EHV distribution networks introduced previously. For LV networks, it is not practically to conduct the same simulation process in each node with nodal injection or withdrawn as EHV networks because of the extensiveness of network configuration and lack of detail data. Therefore, firstly, the distribution of utilisation level of networks is estimated using triangular distribution.

Secondly, for the assets with limited different number of utilisation level, the time to reinforce can be derived. Finally the LRIC charges for LV networks seeks to reflect the impact on future investment in network components as a result of the load growth pattern against the DNOs 'ideal' load growth at the planning stage, rather than nodal injection. This is to indicate the impact of underlying load growth rate on future reinforcement and potentially provide economic signals for LV customers to control their expansion of load increase.

Charges from the LIRC model can reflect the true incremental costs and therefore provide more efficient economic signals compared with the ARC model. However, it cannot ensure full cost recovery especially when assets' utilisation is low. Conversely, the ARC model can ensure the full recovery of the reinforcement costs given load growth.

# Chapter 11

# Future Works

## Cost/benefit-Reflective Incentives for Micro generation

Governments in Europe see MG as a real alternative in reducing carbon emission and improving supply efficiency and security, incentives for MG are therefore on the rise. Currently in the UK, Feed-In tariff has already been introduced to give customers incentives if they install MGs. However, this kind of incentives does encourage more people to accept MGs but less considers the impact of MGs on distribution networks. Therefore, it will potentially bring economic pressures for government or technical burdens to distribution networks such as reverse flow happens if too much electricity generated by MGs in the network. In this case, cost-reflective incentives should be developed to encourage reasonable and effective MGs installation. The desirable incentives should recognise benefits brought by MGs for distribution networks such as investment deferral, which could provide economic signals to achieve optimal MGs installation.

## Network Pricing for HV networks: Distributed Generation

The charging model proposed for HV distribution networks can provide economic signals for DGs. However, further analysis should be carried out to better accommodate DGs in distribution networks. Firstly, distinguishing generation dominated areas from demand dominated areas is necessary to understand network condition. According to the proposed model, credits are given to DGs to reward their contribution in reducing assets' utilisation and therefore deferring network investment. However, with the increasing installation of DG under the reward schemes, concerns could appear as investments in certain parts of networks are driven by DG, as opposed to demand customers. Therefore, the issue should be addressed properly in further works. Secondly, the characteristics of intermittency of most renewable DGs should be modelled. The modelling should better reflect the varied output of DGs and therefore treat DGs properly. The work could play vital role in efficient network investment in planning stage.

## Enhancing the Statistical Approach to Quantify Reinforcement Costs in Large-scale LV networks

The proposed approach can be used to evaluate future investment cost in a LV network with very limited sensory information. However, the model needs to be further enhanced to represent network condition more preciously. This could be achieved by using the increasing deployment of smart meters. With the presence of smart meters, more detailed load information at end users will become available. This will be extremely valuable for refining the parameters used in the proposed planning tool to model the system loading levels, i.e. the minimum, maximum and averaging loading conditions of the LV network assets. Furthermore, more accurate demand information will inform the development of more representative probabilistic distribution of assets utilisation, which can significantly improve the accuracy of the long-term LV network investment evaluation. Meanwhile, the same demand growth pattern is assumed in urban, suburban and rural areas. In further works, all sorts of different load growth rate could be considered to represent demand growth pattern more preciously.

# Appendix

**A-1.Electricity Sales in All the Local Areas of Central Network East Midlands**

| | | Domestic consumers | Commercial and industrial consumers | All consumers |
|---|---|---|---|---|
| **NUTS4 Code** | **NUTS4 Area** | Sales 2008 - GWh | Sales 2008 - GWh | Sales 2008 - GWh |
| UKF1301 | Amber Valley | 224.5 | 383.8 | 608.3 |
| UKF1501 | Ashfield | 195.8 | 409.2 | 604.9 |
| UKF1502 | Bassetlaw | 209.5 | 365.4 | 574.8 |
| UKF2201 | Blaby | 162.6 | 232.2 | 394.8 |
| UKF1201 | Bolsover | 123.2 | 218.2 | 341.4 |
| UKF3001 | Boston | 125.7 | 223.1 | 348.7 |
| UKF1601 | Broxtowe | 188.7 | 197.0 | 385.7 |
| UKF2202 | Charnwood | 277.6 | 510.5 | 788.1 |
| UKF1202 | Chesterfield | 167.5 | 271.8 | 439.3 |
| UKF2301 | Corby | 98.0 | 392.1 | 490.0 |
| UKF2302 | Daventry | 175.0 | 272.7 | 447.7 |
| UKF1100 | Derby | 410.2 | 752.3 | 1,162.5 |
| UKF1303 | Derbyshire Dales | 152.9 | 315.8 | 468.7 |
| UKF3002 | East Lindsey | 303.9 | 395.2 | 699.0 |
| UKF2303 | East Northamptonshire | 170.2 | 173.5 | 343.7 |
| UKF1304 | Erewash | 194.2 | 279.3 | 473.5 |
| UKF1602 | Gedling | 209.0 | 177.5 | 386.5 |
| UKF2203 | Harborough | 169.1 | 224.0 | 393.1 |
| UKF1305 | High Peak | 166.1 | 600.0 | 766.1 |
| UKF2204 | Hinckley and Bosworth | 195.8 | 263.9 | 459.7 |
| UKF2304 | Kettering | 170.0 | 243.8 | 413.8 |
| UKF2100 | Leicester | 453.9 | 1,048.0 | 1,501.9 |
| UKF3003 | Lincoln | 148.4 | 308.9 | 457.3 |
| UKF1503 | Mansfield | 168.4 | 266.2 | 434.5 |
| UKF2205 | Melton | 102.6 | 184.2 | 286.9 |
| UKF1504 | Newark and Sherwood | 214.6 | 417.9 | 632.6 |
| UKF1203 | North East Derbyshire | 166.8 | 259.8 | 426.6 |
| UKF3004 | North Kesteven | 207.8 | 284.8 | 492.7 |

| | | | | |
|---|---|---|---|---|
| UKF2206 | North West Leicestershire | 176.2 | 399.2 | 575.4 |
| UKF2305 | Northampton | 378.5 | 687.7 | 1,066.2 |
| UKF1400 | Nottingham | 489.3 | 939.0 | 1,428.3 |
| UKF2207 | Oadby and Wigston | 89.1 | 130.4 | 219.5 |
| UKF1603 | Rushcliffe | 204.7 | 231.1 | 435.7 |
| UKF2208 | Rutland | 79.4 | 315.7 | 395.1 |
| UKF1302 | South Derbyshire | 166.9 | 350.7 | 517.6 |
| UKF3005 | South Holland | 184.1 | 324.0 | 508.1 |
| UKF3006 | South Kesteven | 272.2 | 429.5 | 701.7 |
| UKF2306 | South Northamptonshire | 194.1 | 230.7 | 424.8 |
| UKF2307 | Wellingborough | 135.8 | 254.9 | 390.7 |
| UKF3007 | West Lindsey | 173.4 | 216.6 | 390.0 |

# Publications

Y. Zhang, F. Li, Zechun Hu and Gavin Shaddick, "Quantification of Low Voltage Network Reinforcement Costs: a Statistical Approach", *IEEE Transactions on Power Systems.*

C. Gu, Y. Zhang, F. Li and W. Yuan, ''Economic Analysis of Interconnecting Distribution Substations via Superconducting Cables'',*IEEE Power & Energy Society General Meeting,* 2012.PES '12.

Y. Zhang, and F. Li, "Network charging for High Voltage Radial Distribution Networks", *IEEEPower & Energy Society General Meeting,* 2011.PES '11.

Y. Zhang, C. Gu and F. Li, "Evaluation of Investment Deferral Resulting from Micro Generation for EHV Distribution Networks", IEEE Power & Energy Society General Meeting, 2010. PES '10.

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